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March 24, 2026

**VIA ELECTRONIC FILING**

Adam Teitzman, Commission Clerk
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20260020-EI
Petition for Determination of Need for Andytown-Oasis Transmission Lines Project in Broward and Miami-Dade Counties, by Florida Power & Light Company

Dear Mr. Teitzman:

Please find enclosed for filing in the above-referenced docket the Direct Testimony and Exhibits of Ted J. Thomas on behalf of Intervenor, Environmental Defense Fund, Inc. ("EDF"). This filing is being made via the Florida Public Service Commission's web-based electronic filing portal.

Please let me know if you should have questions regarding this submission.

Cordially yours,

Robert Scheffel Wright

Robert Scheffel Wright

RSW:rjc
Enclosure

## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic mail on this 24th day of March, 2026, to the following:

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*/s/Robert Scheffel Wright*
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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| In re: Petition for Determination of Need For Andytown-Oasis Transmission Lines Project in Broward and Miami-Dade Counties, by Florida Power & Light Company | ) ) ) ) ) | DOCKET NO. 20260020-EI FILED: MARCH 24, 2026 |

# DIRECT TESTIMONY

# OF TED THOMAS

# On Behalf of

# Environmental Defense Fund, Inc.

**IN RE: PETITION FOR DETERMINATION OF NEED FOR ANDYTOWN-OASIS TRANSMISSION LINES PROJECT IN BROWARD AND MIAMI-DADE COUNTIES, BY FLORIDA POWER & LIGHT COMPANY, DOCKET NO. 20260020-EI**

**DIRECT TESTIMONY OF TED THOMAS**

**ON BEHALF OF ENVIRONMENTAL DEFENSE FUND, INC.**

## INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is Ted Thomas, and my business address is 1910 Navarre School Road, Unit 5001, Navarre, Florida 32566.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Environmental Defense Fund, Inc., commonly known as EDF, an international not for profit organization that advocates for pragmatic solutions to environmental issues in all sectors of the world economy, including energy and electricity, based on sound science, economics, law, and public policy.

**Q. Please summarize your educational background and professional experience with respect to utility regulation.**

A. I earned a Bachelor of Arts degree with High Honors in Political Science from the University of Arkansas in 1986 and a Juris Doctor from the University of Arkansas School of Law in 1988. My experience in utility regulation includes serving as an Administrative Law Judge at the Arkansas Public Service Commission and serving as a Commissioner and Chairman of the Arkansas PSC from 2015 until 2022. I am a past member and past president of the Organization of MISO States, an organization of states whose transmission systems are part of the Midcontinent Independent System Operator ("MISO"), the electric grid operator for the central United States. MISO ensures the reliable operation of the transmission grid serving 15 states and the Canadian province of Manitoba. During my tenure on the Arkansas PSC, I also served as a member of the Committee on Electricity of the National Association of Regulatory Utility Commissioners ("NARUC"). I also previously served as a member of the Arkansas House of Representatives, a budget director for Governor Mike Huckabee, and a prosecutor.

Following my service on the Arkansas PSC, I founded and serve as a principal of Energize Strategies, a consulting firm that specializes in utility issues, including issues relating to the regulation of transmission systems. Although I am not appearing as an attorney in this proceeding, I am licensed to practice law in Arkansas, and I am admitted to practice before the United States Supreme Court, the United States Courts of Appeals for the District of Columbia and the Eighth Circuit, and the United States District Court for the Eastern and Western Districts of Arkansas.

**Q. Have you previously testified in proceedings before utility regulatory authorities? If so, please briefly describe your prior testimony and presentations before regulatory authorities.**

A. Yes, in January 2025 I testified before the Indiana Utility Regulatory Commission in Cause No. 46183, in May 2025 before the Georgia Public Service Commission in Dockets No. 56002 and 56003, and in November 2025 before the Indiana Utility Regulatory Commission in Cause No. 46301.

**Q. Are you testifying as an expert in this proceeding? If so, please state the area or areas of your expertise relevant to your testimony.**

A. Yes, I am testifying as an expert on appropriate principles and considerations to be followed by public utilities and public utility regulatory authorities in making planning and investment decisions for transmission and related utility power supply assets.

**Q. Are you sponsoring any exhibits in this case?**

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit TT-1 | Résumé of Ted Thomas; |
| Exhibit TT-2 | FERC Order No. 1000; |
| Exhibit TT-3 | FERC Order 1920; |
| Exhibit TT-4 | FERC Order 1920-A; |
| Exhibit TT-5 | FERC Order 1920-B; |
| Exhibit TT-6 | 2025 Transmission Planning and Development Report Card (Feb 2026); |
| Exhibit TT-7 | DOE National Transmission Needs Study (Oct 2023); |
| Exhibit TT-8 | National Transmission Planning Study – Chapter 1; |

| | | |
|---|---|---|
| Exhibit TT-9 | National Transmission Planning Study – Chapter 2; |
| Exhibit TT-10 | National Transmission Planning Study – Chapter 3; |
| Exhibit TT-11 | National Transmission Planning Study – Chapter 4; |
| Exhibit TT-12 | National Transmission Planning Study – Chapter 5; |
| Exhibit TT-13 | National Transmission Planning Study – Chapter 6; |
| Exhibit TT-14 | National Transmission Planning Study – Executive Summary; and |
| Exhibit TT-15 | Delaying Transmission Increases Cost and Reduces Benefits for Consumers (2025). |

## PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. EDF engaged me to provide my professional opinions regarding whether FPL's proposed Andytown-Oasis Transmission Lines Project, abbreviated in my testimony as the "Andytown-Oasis Project" or the "Project," is consistent with sound transmission planning and public interest principles, including whether it is consistent with the requirements established by orders of the Federal Energy Regulatory Commission ("FERC"). The specific orders to which I will refer most

frequently are Order No. 1000 and three related orders, Order No. 1920, Order No. 1920-A, and Order No. 1920-B, which I will refer to collectively as "Order No. 1920."

**Q. Please summarize your opinions regarding FPL's proposed Andytown-Oasis Transmission Lines Project.**

A. FPL conducts transmission planning in conjunction with the Florida Reliability Coordinating Council ("FRCC"). Both FPL's and the FRCC's planning activities fail to reliably ensure and demonstrate that transmission planning and investment decisions will serve the public interest . Although their planning processes are nominally called "regional," they actually constitute localized planning that fails to meet appropriate transmission planning criteria, including optimizing reliability and optimizing the delivery of reliable, low-cost power to utility customers in Florida. Accordingly, I recommend that the Florida Public Service Commission direct FPL to conduct true regional transmission planning analyses, with full and timely opportunities for stakeholder involvement, consistent with the requirements of the FERC Orders.

## BACKGROUND: FEDERAL AND STATE REGULATORY FRAMEWORK FOR REGIONAL TRANSMISSION PLANNING

**Q. Please summarize the regulatory framework applicable to transmission planning.**

A. FERC has overall regulatory responsibility for transmission planning and regulation pursuant to the Federal Power Act (16 U.S.C. §§ 791 *et seq*.). Through numerous orders, FERC requires that utilities participate in regional planning and has established principles and considerations applicable to utility transmission planning. It is important that states consider these principles when making decisions.

**Q. What is your understanding of the function of FERC Order No. 1000 and Order No. 1920 and the obligations that utilities have under those Orders?**

A. Those are FERC's regional planning orders, which require that utilities subject to FERC's jurisdiction under the Federal Power Act participate in regional transmission planning that meets certain specified standards. Planning processes consistent with these standards were

initially required by Order No. 1000. Subsequently, in Order No. 1920, FERC found that existing regional planning processes were unjust and unreasonable and established further requirements in Order No. 1920 to direct development of just and reasonable replacements. What this means for utilities like FPL is that they must engage in planning with their regional grid planner – in this case the Floridia Reliability Coordinating Council, alongside the other Florida utilities – look at the system needs statewide, and find solutions that cost-effectively address these overall needs. Under Order No. 1000, these processes could be limited to region-wide reliability violations. Under Order No. 1920, they must look at both reliability and economic system needs. And crucially, under Order No. 1920, the forecast for the needs looks 20 years out into the future so that these decades-long assets can be planned for what comes up at these later junctures.

## ASSESSMENT OF FPL'S AND THE FRCC'S REGIONAL PLANNING PROCESS

**Q. Please explain how the FRCC regional planning process is supposed to operate.**

A. Following the issuance of FERC Order No. 1000, transmission planning regions were required to establish formal processes to identify and evaluate regional transmission alternatives that could meet system needs more efficiently or cost-effectively than localized utility projects. In Florida, the FRCC complies with this mandate through its Biennial Transmission Planning Process (BTPP). During this two-year cycle, the FRCC conducts a "Proactive Planning" analysis. The stated goal is to determine if any proposed regional project qualifies as a Cost Effective or Efficient Regional Transmission Solution (CEERTS). If a CEERTS is identified, its costs would theoretically be allocated regionally, saving individual ratepayers from bearing the full burden of localized infrastructure.

**Q. Does this "Proactive Planning" analysis actually result in the selection of cost-effective regional projects?**

A. No. The process is structurally captured by the very utilities it is meant to oversee. Potential regional solutions are evaluated by the FRCC's Regional Projects Subcommittee (RPS). The members of this subcommittee are the transmission planners and engineers from

Florida's incumbent monopolies, including FPL. Consequently, when a regional alternative is proposed that might replace or optimize a localized project like the Andytown-Oasis Project, it is FPL and its peer utilities that evaluate the proposal. Unsurprisingly, they consistently conclude that their own siloed, utility-by-utility transmission plans are already the optimal path forward. The incumbent utilities are effectively allowed to grade their own homework.

**Q. What has been the empirical result of this FRCC process since FERC Order No. 1000 was implemented?**

A. The historical record is unequivocal. Since the inception of the Order 1000 regional planning framework over a decade ago, **exactly zero** CEERTS have been selected, approved, or constructed by any utility in Florida through the FRCC process. Every single biennial cycle, the FRCC issues a summary report concluding that no CEERTS projects were identified.

**Q. What does this "zero project" track record mean for the Commission's evaluation of the Andytown-Oasis Project?**

A. It means this Commission cannot rely on the FRCC process as a proxy for regional planning directed at identifying efficient or cost-effective projects. A regional planning process that has yielded zero regional projects in over a decade is a compliance exercise, not a functional planning tool. Because the FRCC framework systematically fails to advance regional efficiencies, it is incumbent upon the FPSC to rigorously scrutinize FPL's application. By presenting the Andytown-Oasis Project in isolation, without genuinely evaluating how right-sizing the Project could resolve broader system constraints, identified in independent studies like the National Transmission Planning Study performed by the U.S. Department of Energy (Exhibits TT-8 through TT-14 to my testimony), FPL is perpetuating a fragmented, piecemeal transmission development process. This artificially inflates infrastructure costs for ratepayers and fails the statutory mandate to provide the most cost-effective alternative.

**Q. Does FPL's proposed localized solution for the Andytown-Oasis Project align with the modern regulatory framework established by FERC Order No. 1920?**

A. No, it fundamentally frustrates the core intent of that order. The modern regulatory framework relies on local transmission needs serving as the economic building blocks for highly efficient, right-sized regional solutions. FERC Order No. 1920 is explicitly designed to capture the profound economies of scale that occur when neighboring utilities coordinate to solve multiple system constraints with shared, high-capacity infrastructure. By rushing to authorize a capital-intensive, strictly local solution to this single constraint, FPL is actively circumventing the efficiencies that Order 1920 is designed to achieve for ratepayers.

**Q. How does approving a localized project like the Andytown-Oasis Project today circumvent and frustrate the FERC's purposes of future regional planning under Order 1920?**

A. It results in what is essentially the preemptive starvation of the regional planning process. Regional planning requires identified local

needs to justify the cost and scale of a broader regional project. If FPL is permitted to solve all of its isolated, localized constraints piecemeal today through applications like this one, it will enter future regional planning cycles with no stated needs. This guarantees that comprehensive, cost-sharing regional projects never materialize because the foundational local needs have already been functionally erased from the board.

**Q. Does the Florida Reliability Coordinating Council regional planning process ensure that FPL's proposed Andytown-Oasis Project is the most cost-effective alternative for ratepayers?**

A. No, it does not. FPL routinely points to its participation in the FRCC's regional planning process as evidence that its localized transmission plans have been vetted for regional efficiency. However, a structural and historical analysis of how the FRCC implements its regional planning mandate demonstrates that this process acts as a rubber stamp for incumbent utilities' localized plans, rather than a genuine mechanism for identifying cost-saving regional infrastructure.

**Q. What is the ultimate impact on ratepayers if FPL's approach is approved?**

A. It artificially forecloses the opportunity for ratepayers to benefit from the cost savings of regional planning, reducing FPL's obligations under Order 1920 to a mere paper exercise—compliance in name only. Ratepayers are left funding highly expensive, fragmented local projects, while the utility avoids the scrutiny and shared costs of a genuinely collaborative, right-sized regional grid.

**Q. How does a well-planned transmission grid directly impact the cost of energy for Florida ratepayers?**

A. The transmission grid dictates the economics of the entire generation fleet. The system is operated through what is known as "security-constrained economic dispatch." This means the grid operator dispatches the lowest-cost generation resource available to serve load, without regard to who owns it or where the load is located, provided the grid can reliably accommodate the flow of that power. As load increases, the system looks for the next cheapest unit

to turn on. It is critical to understand that in this real-time dispatch process, only the *variable* cost of generation is considered.

**Q. Why is the distinction between variable and fixed costs so important when evaluating the Andytown-Oasis transmission Project?**

A. This distinction is critical because renewable resources, like utility-scale solar, have essentially zero variable costs. In a dispatch determination, zero-variable-cost resources will always be the absolute cheapest energy available. However, that cheap energy is entirely useless if the transmission grid is too constrained to deliver it to the load centers. When FPL proposes a narrowly tailored, localized project like Andytown-Oasis that fails to maximize regional transfer capacity, it physically limits the geographic reach of the grid. This restricts the amount of zero-variable-cost solar that can compete in the economic dispatch, forcing the system to rely on more expensive, volatile fossil-fuel generation to meet demand.

## ELEMENTS OF OPTIMAL TRANSMISSION PLANNING

**Q. From your perspective as a former public service commissioner, what are the elements of optimal transmission planning that FPL should have applied here?**

A. Optimal transmission planning requires the simultaneous consideration of all benefit streams over a long planning horizon. The baseline criterion for any project is compliance with NERC reliability standards—but that is merely the floor. A prudent utility must optimize that reliability mandate with other criteria, specifically the energy savings generated by unlocking broader economic dispatch. Optimal planning actively seeks opportunities where a transmission corridor can be "right-sized" so that the expected generation savings pay for all or part of the infrastructure costs. FPL's approach with the Andytown-Oasis Project completely ignores this optimization, focusing strictly on a localized reliability fix while leaving massive economic benefits on the table.

**Q. How does the concept of risk mitigation apply to transmission planning in a growing state like Florida?**

A. Transmission is a multi-decadal asset; its benefits compound over time while its capital costs depreciate. In a state experiencing rapid load growth and a transition toward renewable energy, the greatest risk to ratepayers is not overbuilding transmission—it is underbuilding it. Expanding transmission capacity serves as a cost-free hedge against generation risk because it diversifies the portfolio of accessible resources. By proposing a localized, fragmented project instead of a robust, right-sized regional solution, FPL is exposing ratepayers to the severe economic risk of future grid congestion and the inevitable need to fund redundant, piecemeal upgrades a few years down the line. This is consistent with the findings in a 2025 report by GridStrategies, "Delaying transmission increases costs and reduces benefits for consumers," which is included as Exhibit TT-15 to my testimony.

**Q. Does FPL's own executive management recognize the systemic risks of failing to develop robust regional transmission?**

A. Yes, they do. While FPL's transmission planners are presenting the Andytown-Oasis Project to this Commission as a narrow, localized

reliability fix, FPL's financial executives have painted a starkly different picture of the grid's macro-level needs. During FPL's 2025 base rate case, the company's Vice President of Finance, Scott Bores, explicitly testified regarding the severe transmission risks and constraints facing southeast Florida.

**Q. What specific transmission vulnerabilities did FPL identify in that testimony?**

A. Mr. Bores testified that Miami-Dade and Broward counties represent nearly 40% of FPL's customers and almost half of its forecasted load. Because there is limited land available to build new generation in this South Florida load pocket, FPL is forced to rely heavily on generation located outside the FPL southeast Florida service territory and transmit it southward. Furthermore, Mr. Bores noted that because Florida's only interregional ties are at the extreme north end of the state, the peninsula has a uniquely high exposure to voltage issues, system stability failures, system separation, and under-frequency load shedding.

**Q. Did FPL's management explicitly link these vulnerabilities to a lack of regional transmission options?**

A. Yes. In a highly revealing statement, Mr. Bores testified: *"FPL's ability to supply power purchased from outside of Florida if there is a significant need or disruption due to extreme weather events is more constrained than utilities with more access to regional options."* By emphasizing the difficulty in securing power transfers from outside the state, his statement underlines the importance of power transfers within the state to address significant needs. He further noted that this constraint also applies to their heavy reliance on a limited number of natural gas pipelines, compounding the risk during tropical weather events.

These vulnerabilities are identified and discussed at some length in the National Transmission Needs Study published by the U.S. Department of Energy in October 2023. This Study is included here as Exhibit TT-7 to my testimony.

**Q. How do you, as a former regulator, reconcile Mr. Bores's admissions with FPL's current application for the Andytown-Oasis Project?**

A. I cannot reconcile them, because they are fundamentally contradictory. FPL's executive management has clearly identified that the primary threat to the Florida grid—and specifically to the South Florida load center—is a lack of regional connectivity and transmission import capacity. Yet, the application before the Commission today is a fragmented, localized project that does not meaningfully expand Florida's access to those necessary regional options.

**Q. What are the regulatory consequences of this contradiction?**

A. FPL is engaging in disjointed, sub-optimal planning that results in higher costs and other adverse consequences to its ratepayers. FPL is using the severe risks of regional isolation to justify rate increases in one docket, while simultaneously ignoring those exact regional solutions in its transmission planning docket. If FPL's ability to supply power during extreme weather is critically constrained by a lack of

options from outside the region—as their own VP of Finance attests—then the prudent, cost-effective solution is to aggressively pursue comprehensive, high-capacity regional transmission and advanced grid-enhancing technologies to maximize north-to-south flow. By settling for a localized project that leaves South Florida functionally isolated from broader regional support, FPL is ignoring its own diagnosed vulnerabilities at the ratepayer's expense.

**Q. If FPL were to argue that a localized need determination proceeding before the Commission is an "inappropriate forum" to address broader regional transmission solutions, how would you respond as a former state public service commission chairman?**

A. I strongly disagree with that premise. They argue that "regional planning belongs at the regional level," attempting to restrict the state commission's focus to a single, isolated line. However, state regulators are the ultimate guardians of the ratepayer’s wallet. It is the retail ratepayer who bears the financial burden of these infrastructure investments. If a utility’s localized proposal ignores a more cost-effective regional alternative, it is squarely within the

jurisdiction—and indeed, it is the statutory duty—of the state commission to scrutinize that failure. The state commission is not the wrong forum; when regional planning processes fail, the state commission is the *only* forum left to protect the consumer.

**Q. Why can the FPSC not simply rely on the existing regional transmission planning process to ensure that it builds low-cost transmission?**

A. The Commission cannot rely on the FRCC process because the existing FRCC regional planning framework in Florida is structurally and systemically defective and inadequate. This assessment is confirmed by the low grade – an "F" – assigned to Florida's transmission planning efforts by the 2025 Transmission Planning and Development Report Card published in February 2026 by Americans for a Clean Energy Grid, included as Exhibit TT-6 to my testimony. Under the current federal framework (FERC Order No. 1000), the Florida Reliability Coordinating Council (FRCC) conducts a Biennial Transmission Planning Process. However, this process is structurally dominated by the incumbent utilities themselves. When a regional

solution is proposed that might displace a utility's localized, capital-intensive project, it is the incumbent utilities' own engineers who evaluate it. Unsurprisingly, this self-grading system has produced a staggering empirical result: since the inception of Order 1000 over a decade ago, exactly zero regional transmission projects have been selected, approved, or built through the FRCC process.

**Q. What does the failure of the Order 1000 process mean for this specific docket?**

A. It means FPL cannot hide behind the FRCC. FPL cannot legitimately argue that the Andytown-Oasis Project was thoroughly vetted against regional alternatives when the historical record proves that the FRCC's regional vetting process is a compliance fiction that invariably defaults to localized utility buildouts. As a former regulator, I can assure you that when the regional mechanism is paralyzed by incumbent self-interest, the state commission must step in and rigorously enforce its mandate to ensure the low-cost electrical energy is capable of being dispatched.

**Q. How does the recent issuance of FERC Order No. 1920 impact FPL's planning obligations?**

A. FERC Order No. 1920 was explicitly designed by the federal government to fix the systemic failures of Order 1000. It mandates that utilities adopt a modern, comprehensive, and forward-looking approach to regional planning. Crucially, it requires transmission providers to look holistically at long-term system needs and rigorously evaluate whether "right-sizing" infrastructure or deploying Advanced Transmission Technologies ("ATTs") and Grid-Enhancing Technologies ("GETs") can resolve multiple local constraints through highly efficient, shared regional facilities.

**Q. Is FPL embracing the modern planning principles of FERC Order No. 1920 with its proposed Andytown-Oasis Project?**

A. No, this application represents the exact opposite approach. Rather than embracing the comprehensive, cost-sharing principles that Order 1920 demands, FPL is presenting a narrowly tailored, piecemeal local project. By rushing to authorize this capital-intensive, strictly local solution right now, FPL is preemptively circumventing

the upcoming Order 1920 process. If utilities are permitted to solve all of their isolated constraints piecemeal today, they will enter future regional planning cycles claiming they have "no stated needs," ensuring that comprehensive regional projects never materialize. FPL is using this state forum to lock in local capital expenditures before the modern federal requirement for regional efficiency can take root.

**Q. What is your recommendation to the Commission regarding FPL's attempt to dismiss regional solutions in this forum?**

A. The Commission must reject the argument that regional efficiencies are outside the scope of this proceeding. The Andytown-Oasis Project illustrates precisely why state commissions must demand evidence of holistic planning. Approving this fragmented local project without forcing FPL to genuinely evaluate regional economies of scale and advanced technologies effectively rewards the circumvention of federal planning goals and guarantees higher costs for Florida ratepayers.

**Q. What is your ultimate recommendation to the Commission regarding FPL's planning methodology?**

A. I recommend that the Commission view transmission expansion not merely as a localized reliability bandage, but as a comprehensive tool to mitigate economic risks for customers. Because FPL has failed to simultaneously evaluate all benefit streams—including the deployment of Grid-Enhancing Technologies and the profound generation savings enabled by regional economic dispatch—the Commission cannot conclude that this project represents the optimal, lowest-cost solution for Florida.

While the Project will likely meet basic reliability criteria, it will fail to satisfy the statutory criterion of ensuring abundant, low-cost electrical energy to assure the economic well-being of the residents and businesses of Florida because it will result in more costly electric service and non-optimal development of the Florida transmission grid over the medium term and long term.

**Q. What should the Commission do to ensure that FPL's and the state's transmission needs are met in the manner that best meets**

**the statutory criteria and best serves the public interest of all Floridians?**

The Commission should direct FPL to consider the regional needs that were identified by FRCC through the last regional Biennial Transmission Planning, and where those previous studies do not appropriately reflect regional needs, conduct legitimate, robust regional transmission planning studies consistent with the requirements of the FERC's orders to determine which regional needs could be jointly served by a transmission solution that meets the purpose of the Project. The Commission should further require that FPL engage all stakeholders in a timely way in those planning studies, with stakeholders having full access to FPL's modeling in a reasonable time frame.

## THE PROCEDURAL SCHEDULE IN THIS DOCKET FAILS TO PROVIDE THE FLORIDA PSC WITH A COMPLETE AND RELIABLE EVIDENTIARY RECORD

**Q. Based on your experience as a former utility commissioner, what is your opinion of the procedural schedule in this docket?**

A. During my tenure as Chairman of the Arkansas Public Service Commission, I learned a fundamental truth about utility regulation: a Commission is only as good as the evidentiary record placed before it. Regulators rely entirely on the adversarial process to uncover the truth about a project's cost-effectiveness. When, as is the case here, the procedural schedule for this docket is so aggressively compressed that it functionally hobbles intervenors, the adversarial process breaks down and the Commission is left with an incomplete evidentiary record. The Commission is left flying blind, forced to rely almost exclusively on the utility's inherently biased, proprietary modeling.

**Q. From a regulator's perspective, why are stakeholder and intervenor perspectives so critical in transmission need determinations?**

A. Intervenors provide the essential crucible of independent scrutiny. A utility like FPL has massive financial resources and spends months, if not years, behind closed doors developing a highly polished application that justifies its preferred capital expenditures. Without robust intervenor participation, the Commission operates in an echo

chamber. Intervenors are the ones who stress-test the utility's assumptions. They ask the hard questions about whether Grid-Enhancing Technologies were bypassed, and they introduce independent, regional data—like the constraint mapping provided in the University of Florida analyses—that the utility conveniently left out. Frankly, without the rigorous pushback and alternative solutions provided by expert intervenors, a "need determination" degrades into a mere rubber stamp for the utility's capital expansion plans. These are the meaningful contributions that Intervenors in cases like this can and do make, but only where they are provided with adequate opportunities to participate fully in the regulatory process.

**Q. Given that context, does the 13-day window for intervenor testimony in this docket allow for adequate stakeholder engagement?**

A. Absolutely not. FPL filed its petition and supporting testimony on March 11, 2026, with intervenor testimony due on March 24, 2026. Allocating a mere 13 days to review hundreds of pages of highly

technical engineering filings, conduct substantive analysis, and draft expert testimony is a structural barrier to meaningful participation.

**Q. Why is this ultra-compressed schedule particularly insufficient for a transmission project of this nature?**

A. The complexity of modern transmission constraints requires deep, incredibly thorough evaluation. You cannot adequately analyze regional power flows, NERC reliability violations, and the viability of alternative technologies in less than two weeks. The extreme information asymmetry here is staggering. To even attempt to provide meaningful feedback, organizations like the EDF had to prospectively collaborate with the University of Florida to develop independent transmission constraint maps. That level of independent analysis is expensive, time-consuming, and inaccessible to most ratepayers. A 13-day window all but ensures that highly complex localized projects will get built simply because they were filed, as no intervenor can realistically marshal the resources to fully evaluate and contest the utility's models in that timeframe.

**Q. How does this lack of adequate review time contrast with modern industry standards for transmission planning?**

A. It flies directly in the face of the robust stakeholder requirements established by FERC Order No. 1920. The modern federal framework explicitly recognizes that comprehensive, transparent stakeholder engagement is absolutely vital for addressing the intricacies of the grid and fulfilling the mandate to deliver cost-effective solutions for consumers. FPL's reliance on this ultra-compressed, localized proceeding paints a troubling picture: it suggests a planning culture that actively avoids stakeholder perspectives and independent scrutiny.

**Q. What is your ultimate conclusion regarding this procedural timeline?**

A. A regulatory process that relies on a 13-day review window to authorize hundreds of millions of dollars in ratepayer-funded infrastructure is structurally flawed. It deprives the Florida Public Service Commission of compelling, independent testimony and severely narrows the range of perspectives considered. Ultimately, it

harms Florida ratepayers by ensuring the utility's plans face virtually no meaningful technical challenges.

## SUMMARY AND CONCLUSIONS

**Q. Please summarize the main conclusions of your testimony.**

A. FPL's and the FRCC's planning processes are not regional planning in any meaningful way. They are localized processes that fail to consider and address all meaningful options and opportunities that would provide for optimal transmission investments that would serve the public interest and best meet the criteria in the Transmission Line Siting Act. The systemic defects in these planning processes are compounded by the unreasonably short time frame provided for intervenor participation in the planning processes and in the need determination docket. Finally, FPL's and the FRCC's processes fail to comply with the FERC's requirements in Orders 1920, 1920-A, and 1920-B, and accordingly, the Florida PSC should deny FPL's petition and require FPL to conduct studies that comply with the FERC's orders.

**Q. Please summarize your ultimate recommendation to the Commission regarding FPL's need determination petition for the Andytown-Oasis Transmission Lines Project.**

A. The Commission should direct FPL to conduct legitimate, robust regional transmission planning studies consistent with the requirements of the FERC's orders. The Commission should further require that FPL engage all stakeholders in a timely way in those planning studies, with stakeholders having full access to FPL's modeling in a reasonable time frame. The Commission should also increase the period of time that interested parties have to file intervenor testimony in transmission needs proceedings from the 13 days available in this proceeding to a minimum of 30 days.

**Q. Does this conclude your direct testimony?**

A. Yes.

# TED J. THOMAS

1910 Navarre School Road, Unit 5001, Naverre, FL 32566 · (501) 590-7573

## EXPERIENCE

**OCTOBER 2022- PRESENT**

### FOUNDER, ENERGIZE STRATEGIES

- Consulting firm that advises clients with regard to state and federal regulatory policy, RTO market access, DER innovation, and other energy policy matters.

**JANUARY 2015-SEPTEMBER 2022**

### CHAIRMAN, ARKANSAS PUBLIC SERVICE COMMISSION

- Led the state agency responsible for utility regulation in Arkansas.
- Member, Joint Federal-State Task Force on Electric Transmission
- Former president, Organization of MISO states.
- SPP RSC member, chair of Improved Resource Availability Task Force which oversees implementing the SPP board recommendations related to the February 2021 extreme winter weather event.
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136 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-23-000; Order No. 1000]

# Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

(Issued July 21, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule

SUMMARY: The Federal Energy Regulatory Commission is amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. With respect to transmission planning, this Final Rule: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new

interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

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SUPPLEMENTARY INFORMATION:

136 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities — Docket No. RM10-23-000

# ORDER NO. 1000

## FINAL RULE

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Regulatory Text

Appendix A: Summary of Compliance Requirements
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## I. Introduction

1. In this Final Rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements for public utility transmission providers.[1] The reforms herein are intended to improve transmission planning processes and cost allocation mechanisms under the *pro forma* Open Access Transmission Tariff (OATT) to ensure that the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential. This Final Rule builds on Order No. 890,[2] in which the Commission, among other things, reformed the *pro forma* OATT to require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. After careful review of the voluminous record in this proceeding, the Commission concludes that the additional reforms adopted herein are necessary at this time to ensure that rates for Commission-jurisdictional service are just and reasonable in light of changing conditions in the

[1] 16 U.S.C. 824e (2006).

[2] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

industry. In addition, the Commission believes that these reforms address opportunities for undue discrimination by public utility transmission providers.

2. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The Commission appreciates the diversity of opinions expressed by commenters in response to the Notice of Proposed Rulemaking[3] as to whether, in light of the progress being made in many regions, further reforms to transmission planning processes and cost allocation mechanisms are necessary at this time. On balance, the Commission concludes that the reforms adopted herein are necessary for more efficient and cost-effective regional transmission planning. As discussed further below, the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost. The Commission concludes that it is appropriate to act now to ensure that its transmission planning processes and cost allocation requirements are adequate to allow public utility transmission providers to address these challenges more efficiently and cost-effectively. In reaching this conclusion, the Commission has balanced competing interests of various segments of the industry and designed a package of reforms that, in our view, will support the

[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,660 (2010) (Proposed Rule).

development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and allow for consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations (Public Policy Requirements). By "state or federal laws or regulations," we mean enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.

3. Through this Final Rule, we conclude that the existing requirements of Order No. 890 are inadequate. Public utility transmission providers are currently under no affirmative obligation to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes. Similarly, there is no requirement that public utility transmission providers consider transmission needs at the local or regional level driven by Public Policy Requirements. Nonincumbent transmission developers seeking to invest in transmission can be discouraged from doing so as a result of federal rights of first refusal in tariffs and agreements subject to the Commission's jurisdiction. While neighboring transmission planning regions may coordinate evaluation of the reliability impacts of transmission within their respective regions, few procedures are in place for identifying and evaluating the benefits of alternative interregional transmission solutions. Finally, many cost allocation methods in

place within transmission planning regions fail to account for the beneficiaries of new transmission facilities, while cost allocation methods for potential interregional facilities are largely nonexistent.

4. We correct these deficiencies by enhancing the obligations placed on public utility transmission providers in several specific ways. While focused on discrete aspects of the transmission planning and cost allocation processes, the specific reforms adopted in this Final Rule are intended to achieve two primary objectives: (1) ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them. In addition, this Final Rule addresses interregional coordination and cost allocation, to achieve the same objectives with respect to possible transmission solutions that may be located in a neighboring transmission planning region.

5. Certain requirements of this Final Rule distinguish between "a transmission facility in a regional transmission plan," and "a transmission facility selected in a regional transmission plan for purposes of cost allocation."[4] A "transmission facility selected in a

[4] *See infra* P 63.

regional transmission plan for purposes of cost allocation" is one that has been selected, pursuant to a Commission-approved regional transmission planning process, as a more efficient or cost-effective solution to regional transmission needs. As discussed in more detail below, this distinction is an essential component of this Final Rule.

6. Turning to the specific discrete reforms we adopt today, we first require public utility transmission providers to participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. This requirement builds on the transmission planning principles adopted by the Commission in Order No. 890, and the regional transmission planning processes developed in response to this Final Rule must satisfy those principles. These processes must result in the development of a regional transmission plan. As part of our reforms, we also require that the regional transmission planning process, as well as the underlying local transmission planning processes of public utility transmission providers, provide an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that requiring each local and regional transmission planning process to provide this opportunity is necessary to ensure that transmission planning processes identify and evaluate transmission needs driven by relevant Public Policy

Requirements, and support more efficient and cost-effective achievement of those requirements.

7. Second, we direct public utility transmission providers to remove from their OATTs or other Commission-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation.[5] We conclude that leaving federal rights of first refusal in place for these facilities would allow practices that have the potential to undermine the identification and evaluation of a more efficient or cost-effective solution to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. To implement the elimination of such federal rights of first refusal, we adopt below a framework that requires, among other things, the development of qualification criteria and protocols for the submission and evaluation of transmission proposals. In addition, as described in section III.B.3, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission

[5] *See infra* P 313.

facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations. This requirement, however, applies only to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and not, for example, to transmission facilities in local transmission plans that are merely "rolled up" and listed in a regional transmission plan without going through an analysis at the regional level, and therefore, not eligible for regional cost allocation.

8. Third, we require public utility transmission providers to improve coordination across regional transmission planning processes by developing and implementing, through their respective regional transmission planning process, procedures for joint evaluation and sharing of information regarding the respective transmission needs of transmission planning regions and potential solutions to those needs. These procedures must provide for the identification and joint evaluation by neighboring transmission planning regions of interregional transmission facilities to determine if there are more efficient or cost-effective interregional transmission solutions than regional solutions identified by the neighboring transmission planning regions. To facilitate the joint evaluation of interregional transmission facilities, we require the exchange of planning data and information between neighboring transmission planning regions at least annually.

9. Finally, we require public utility transmission providers to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. We also require public utility transmission providers in each transmission planning region to have, together with the public utility transmission providers in a neighboring transmission planning region, a common method, or set of methods, for allocating the costs of a new interregional transmission facility that is jointly evaluated by the two or more transmission planning regions in their interregional transmission coordination procedures. Given the fact that a determination by the transmission planning process to select a transmission facility in a plan for purposes of cost allocation will necessarily include an evaluation of the benefits of that facility, we require that transmission planning and cost allocation processes be aligned. Further, all regional and interregional cost allocation methods must be consistent with regional and interregional cost allocation principles, respectively, adopted in this Final Rule. Nothing in this Final Rule requires either interconnectionwide planning or interconnectionwide cost allocation.

10. The cost allocation reforms adopted today, and the cost allocation principles that each proposed regional and interregional cost allocation method or methods must satisfy, seek to address the potential opportunity for free ridership inherent in transmission services, given the nature of power flows over an interconnected transmission system. In particular, the principles-based approach requires that all regional and interregional cost

allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits. [6] In addition, the Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method.

11. As noted above, the various specific reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that those transmission facilities selected in a regional transmission plan for purposes of cost allocation are the more efficient or cost-effective solutions available. At its core, the set of reforms adopted in this Final Rule require the public utility transmission providers in a transmission planning region, in consultation with their stakeholders, to create a regional transmission plan. This plan will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability, economic and Public Policy Requirements. To meet such requirements more efficiently and cost-effectively, the regional transmission plan must reflect a fair consideration of transmission facilities proposed by nonincumbents, as well as interregional transmission

[6] However, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead rely on participant funding. *See infra* P 723-729.

facilities. The regional transmission plan must also include a clear cost allocation method or methods that identify beneficiaries for each of the transmission facilities selected in a regional transmission plan for purposes of cost allocation, in order to increase the likelihood that such transmission facilities will actually be constructed.

12. The transmission planning and cost allocation requirements in this Final Rule, like those of Order No. 890, are focused on the transmission planning *process*, and not on any substantive outcomes that may result from this process. Taken together, the requirements imposed in this Final Rule work together to remedy deficiencies in the existing requirements of Order No. 890 and enhance the ability of the transmission grid to support wholesale power markets. This, in turn, will fulfill our statutory obligation to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.

13. We acknowledge that public utility transmission providers in some transmission planning regions already may have in place transmission planning processes or cost allocation mechanisms that satisfy some or all of the requirements of this Final Rule. Our reforms are not intended to undermine progress being made in those regions, nor do we intend to undermine other planning activities that are being undertaken at the interconnection level. Rather, the Commission is acting here to identify a minimum set of requirements that must be met to ensure that all transmission planning processes and cost allocation mechanisms subject to its jurisdiction result in Commission-jurisdictional

services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

14. The Commission appreciates the significant work that will go into the preparation of compliance proposals in response to this Final Rule. To assist public utility transmission providers in their efforts to comply, the Commission directs its staff to hold informational conferences within 60 days of the effective date of this Final Rule to review and discuss the requirements imposed herein with interested parties. Moreover, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

### A. Order Nos. 888 and 890

15. In Order No. 888,[7] issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service to others on a basis that is inferior to that which they provide to

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

themselves.[8] Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 and the accompanying *pro forma* OATT implemented open access to transmission facilities owned, operated, or controlled by a public utility.

16. As part of those reforms, Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. For example, the *pro forma* OATT required a public utility transmission provider to account for the needs of its network customers in its transmission planning activities on the same basis as it provides for its own needs.[9] The *pro forma* OATT also required that new facilities be constructed to meet the transmission service requests of long-term firm point-to-point customers.[10] While Order No. 888-A went on to encourage utilities to engage in joint and regional transmission planning with other utilities and customers, it did not require those actions.[11]

17. In early 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT that the Commission identified based on the decade of experience since the issuance of Order No. 888. Among other things, the Commission found that *pro forma*

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[8] Order No. 888, FERC Stats. & Regs. at 31,682.

[9] *See* Section 28.2 of the *pro forma* OATT.

[10] *See* Sections 13.5, 15.4, and 27 of the *pro forma* OATT.

[11] Order No. 888-A, FERC Stats. & Regs. at 30,311.

OATT obligations related to transmission planning were insufficient to eliminate opportunities for undue discrimination in the provision of transmission service. The Commission stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner. Among other shortcomings in the *pro forma* OATT, the Commission pointed to the lack of clear criteria regarding the transmission provider's planning obligation; the absence of a requirement that the overall transmission planning process be open to customers, competitors, and state commissions; and the absence of a requirement that key assumptions and data underlying transmission plans be made available to customers.

18. In light of these findings, one of the primary goals of the reforms undertaken in Order No. 890 was to address the lack of specificity regarding how stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in transmission planning activities, the Commission required each public utility transmission provider to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to its OATT (Attachment K). The Order No. 890 transmission planning principles are: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic

planning studies; and (9) cost allocation for new projects.[12]

19. The transmission planning reforms adopted in Order No. 890 apply to all public utility transmission providers, including Commission-approved RTOs and ISOs. The Commission stated that it expected all non-public utility transmission providers to participate in the local transmission planning processes required by Order No. 890, and that reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as public utility transmission providers.[13] The Commission stated that a coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. However, the Commission did not invoke its authority under FPA section 211A, which allows the Commission to require an unregulated transmitting utility (i.e., a non-public utility transmission provider) to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[14] The Commission instead stated that if it found, on the appropriate record, that non-public utility

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418-601.

[13] *Id.* P 441.

[14] FPA section 211A(b) provides, in pertinent part, that "the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential." 16 U.S.C. 824j.

transmission providers are not participating in the transmission planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

20. On December 7, 2007, pursuant to Order No. 890, most public utility transmission providers and several non-public utility transmission providers submitted compliance filings that describe their proposed transmission planning processes.[15] The Commission addressed these filings in a series of orders that were issued throughout 2008. Generally, the Commission accepted the compliance filings to be effective on December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning processes to satisfy the nine Order No. 890 transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

21. As a result of these compliance filings, regional transmission organization (RTO) and independent system operators (ISO) have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions also have made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional

[15] A small number of public utility transmission providers were granted extensions.

transmission planning processes.[16] These improvements to transmission planning processes have given stakeholders the ability to participate in the identification of regional transmission needs and corresponding solutions, thereby facilitating the development of more efficient and cost-effective transmission expansion plans. This Final Rule expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters.

### B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation

22. In several of the above-noted orders issued in 2008 and early 2009 on filings submitted to comply with the Order No. 890 transmission planning requirements, the Commission stated that it would continue to monitor implementation of these transmission planning processes. The Commission also announced its intention to convene regional technical conferences in 2009.

23. Consistent with the Commission's announcement, Commission staff in September 2009 convened three regional technical conferences in Philadelphia, Atlanta, and

[16] The regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are the North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.

Phoenix, respectively. The focus of the technical conferences was to: (1) determine the progress and benefits realized by each transmission provider's transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnectionwide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing transmission planning processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities and the integration of large amounts of location-constrained generation. Issues discussed at the technical conferences included the effectiveness of the current transmission planning processes, the development of regional and interregional transmission plans, and the effectiveness of existing cost allocation methods used by transmission providers and alternatives to those methods.

24. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments.[17] The October 2009 Notice presented numerous questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission. In response to the October 2009 Notice, the

[17] Federal Energy Regulatory Commission, Notice of Request for Comments, Transmission Planning Processes under Order No. 890; Docket No. AD09-8-000, October 8, 2009 (October 2009 Notice).

Commission received 107 initial comments and 45 reply comments.

### C. Additional Developments Since Issuance of Order No. 890

25. Other developments with important implications for transmission planning have occurred amid the above-noted Order No. 890 compliance efforts on transmission planning and as the Commission gathered information through the technical conferences and the October 2009 Notice discussed above.

26. For example, in February 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), which provided $80 million for the U.S. Department of Energy (DOE), in coordination with the Commission, to support the development of interconnection-based transmission plans for the Eastern, Western, and Texas interconnections. In seeking applications for use of those funds, DOE described the initiative as intended to: improve coordination between electric industry participants and states on the regional, interregional, and interconnectionwide levels with regard to long-term electricity policy and planning; provide better quality information for industry planners and state and federal policymakers and regulators, including a portfolio of potential future supply scenarios and their corresponding transmission requirements; increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and facilitate and accelerate development of renewable energy or other low-carbon generation

resources.[18]

27. In December 2009, DOE announced award selections for much of this ARRA funding. In each interconnection, applicants awarded funds under what DOE defined as Topic A are responsible for conducting interconnection-level analysis and transmission planning. Applicants awarded funds under Topic B are to facilitate greater cooperation among states within each interconnection to guide the analyses and planning performed under Topic A.[19] Broad participation in sessions to date related to this initiative suggest that the availability of federal funds to pursue these goals has increased awareness of the potential for greater coordination among regions in transmission planning.

28. In describing the activities undertaken under this transmission analysis and planning initiative, DOE staff leading the project has explained that its activities are based on the premise that the electricity industry faces a major long-term challenge in ensuring an adequate, affordable and environmentally sensitive energy supply and that an open, transparent, inclusive, and collaborative process for transmission planning is essential to securing this energy supply.[20] To that end, DOE staff has stressed that all

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[18] Department of Energy, *Recovery Act- Resource Assessment and Interconnection-Level Transmission Analysis and Planning Funding Opportunity Announcement*, at 5-6 (June 15, 2009).

[19] *Id.* at 4-8.

[20] Department of Energy, "*DOE Initiative Regarding Interconnection-Level Transmission Analysis and Planning;*" presented at the NGA Transmission Roundtable

(continued…)

stakeholders need to be involved in assessing options to meeting this future need and that ARRA funds are "seed money" to help establish capabilities to address transmission planning issues.[21] In DOE staff's view, the goal of this funding is to help planners develop a portfolio of long-term energy supply and demand for future needs and associated transmission requirements to assess the implications of these alternative future energy scenarios and identify facilities appropriate for consideration in the development of long-term infrastructure plans. Key deliverables of the DOE-funded planning activities are 10- and 20-year plans that analyze the transmission needs of each interconnection under a range of scenarios.

29. While the results of these planning efforts are not yet available, there is already a growing body of evidence that, in DOE's words, "[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario."[22] In its most recent Long-Term Reliability Assessment, North American Electric Reliability Corporation (NERC) identifies 39,000 circuit-miles of projected high-voltage transmission over the next 10 years.[23] NERC estimates that roughly a third of these

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by David Meyer of DOE's Office of Electricity Delivery and Energy Reliability, January 25, 2011.

[21] *Id.*

[22] Department of Energy, *20% Wind Energy by 2030*, at 93 (July 2008).

[23] NERC 2010 Assessment at 22.

transmission facilities will be needed to integrate variable and renewable generation.[24] Much of this investment in renewable generation is being driven by renewable portfolio standards adopted by states. Some 28 states and the District of Columbia have now adopted renewable portfolio standard measures. In addition, there are 9 states with non-binding goals. The key difference is that the states with requirements usually have financial penalties for non-compliance, known as alternative compliance payments. States with non-binding goals usually have no financial penalty, although some have instituted financial incentives for meeting the goal (e.g., Virginia). These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures. Most of these portfolio standards are set to increase annually, further amplifying the potential need for transmission facilities.

## II. The Need for Reform

### A. Proposed Rule

30. In light of the changes occurring within the electric industry, and based on the Commission's experience in implementing Order No. 890 and comments submitted in response to the October 2009 Notice, the Commission issued the Proposed Rule on June

[24] *Id.* at 24.

17, 2010 identifying further reforms to the *pro forma* OATT in the areas of transmission planning and cost allocation. These reforms, discussed in detail below, were aimed at ensuring that the transmission planning and cost allocation requirements established in Order No. 890 continue to result in the provision of Commission-jurisdictional service at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission received roughly 5,700 pages of initial and reply comments in response. Based on these comments, the Commission concludes that amendment of the transmission planning and cost allocation requirements established in Order No. 890 is necessary at this time to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

31. The Commission noted in the Proposed Rule that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. However, the Commission explained that changes in the nation's electric power industry since issuance of Order No. 890 required the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. The Commission stated its intention was not to disrupt the progress being made with respect to transmission planning and investment in transmission infrastructure, but rather to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power

markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

### B. Comments

32. A number of commenters generally support the Commission's decision to initiate a rulemaking proceeding that proposes reforms to the transmission planning and cost allocation processes.[25] Several of these commenters state that inadequate transmission planning and cost allocation processes have impeded the development of transmission infrastructure.[26]

33. For example, Transmission Dependent Utility Systems state that they support the primary objective of the Proposed Rule to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale

[25] *E.g.*, 26 Public Interest Organizations; AEP; American Transmission; AWEA; Anbaric and PowerBridge; Atlantic Grid; Colorado Independent Energy Association; Conservation Law Foundation; Duke; East Texas Cooperatives; Energy Future Coalition; Exelon; Gaelectric; Green Energy Express and 21st Century; Iberdrola Renewables; Imperial Irrigation District; Integrys; ISO New England; ITC Companies; MidAmerican; Multiparty Commenters; National Audubon Society; National Grid; New York ISO; New York PSC; NextEra; Northwest & Intermountain Power Producers Coalition; Old Dominion Electric Cooperative; Pennsylvania PUC; Ignacio Perez-Arriaga; Senators Dorgan and Reid; SPP; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; Western Grid Group; Wind Coalition; WIRES; and Wisconsin Electric.

[26] *E.g.*, AEP; AWEA; Exelon; Iberdrola Renewables; ITC Companies; MidAmerican; and NextEra.

markets and ensure that jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. Exelon argues that the current system of disconnected priorities and mixed criteria is simply not working. Pennsylvania PUC encourages the Commission to eliminate the current uncertainty regarding planning and paying for future transmission expansion and upgrades.

34. MidAmerican adds that transmission has grown from an industry sector focused on rebuilds, reliability improvements on existing infrastructure, and construction of generation-dependent interconnection facilities, to one where new and upgraded transmission infrastructure is necessary to effectuate the expansion of regional power markets, promote a more reliable transmission system, accommodate increasing reliance on renewable generation sources, and address the uncertainty of the future role of existing conventional generation. AWEA contends that existing processes for planning and paying for transmission are not sufficient to meet the emerging challenges to the transmission system. AWEA argues that many cost allocation methodologies, as they are applied today, are flawed, which together with the fragmented and short-term transmission planning regimes prevalent today, have often stifled investment in, or otherwise led to the inefficient use and inadequate expansion of the nation's transmission network. Senators Dorgan and Reid state that better coordination of regional transmission planning and clarifying cost allocation are two important steps in

overcoming hurdles to developing the nation's vast renewable energy resources and providing clean energy jobs. National Grid contends that the creation of a robust transmission system is imperative to achieving important policy goals, environmental objectives, market efficiencies, and the integration of renewable and distributed resources into electric power markets.

35. NextEra agrees on reply that there is a need for generic reform at this time, stating that there is a sufficient basis for the Commission to proceed with a rulemaking proceeding and that there is ample evidence of the pressing need to enhance the transmission grid. NextEra states that the Proposed Rule demonstrates how and why existing transmission planning and cost allocation rules are inadequate.

36. A number of commenters provide specific examples of developments that further demonstrate the need for reform. Colorado Independent Energy Association states that, in WestConnect, regional transmission providers are not ignoring the problem of transmission constraints, but that development of transmission facilities is not being undertaken and, second, transmission facilities are not being properly sized. In its view, the problems can be traced to the absence of cost allocation methods or the lack of means for identifying the most needed projects and pursuing them to completion.

37. Iberdrola Renewables contends that the lack of transmission expansion in the MISO has led to significant congestion in areas with extensive operating wind generation. It states that the MISO has reported that wind curtailments primarily caused

by congestion averaged five percent for the first six months of 2010 compared with 2 percent on average in 2009. Exelon adds that the lack of coordination between the MISO and PJM transmission planning regions has resulted in a significant increase in the out-of-merit dispatch of generation on the Commonwealth Edison system to maintain NERC reliability requirements. Exelon states that these events have increased from 31 in 2006 to 280 in 2009, and they result in higher costs on the system and excessive wear and tear on equipment.

38. Brattle Group states that it has identified approximately 130 mostly conceptual and often overlapping planned transmission projects throughout the country with a total cost of over $180 billion.[27] It contends that a large portion of these projects will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes. Brattle Group states that many of the benefits associated with economic and public policy projects are difficult to quantify and, without changes to transmission planning and cost allocation processes, many of these projects may fail to gain the needed support for approval, permitting, and cost recovery.

39. Other commenters question the need for Commission action at this time, urging the Commission to be more rigorous in its proposed findings and holdings and arguing

[27] Brattle Group, Attachment at 5.

that the Proposed Rule is not supported by substantial evidence.[28] Large Public Power Council disagrees with the Commission's assertions in the Proposed Rule that state that renewable portfolio standards have contributed to the need for new transmission. Large Public Power Council states that the Commission offers no factual evidence to support its assertions[29] and that the evidence available actually weighs against the Commission. Large Public Power Council states that renewable portfolio standards have not increased meaningfully since the Commission issued Order No. 890. Furthermore, Large Public Power Council cites a report produced by Edison Electric Institute that states that the members of Edison Electric Institute are making significant and growing investments in transmission infrastructure, including interstate projects and projects that will facilitate the integration of renewable resources. Moreover, Large Public Power Council contends

[28] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Salt River Project; Large Public Power Council (each commenter cites *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*)); Large Public Power Council (citing *Associated Gas Distrib. v. FERC*, 824 F.2d 981 (D.C. Cir. 1985) (*Associated Gas Distributors*)); PSEG Companies; Salt River Project; and San Diego Gas & Electric.

[29] Citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148-154 (Large Public Power Council cites to the following two assertions in the Proposed Rule: "further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions." (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 150); and "…the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities across several utility and/or RTO or ISO regions." (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 151)).

that the Commission offers no evidence that the reforms of the type proposed are a necessary or satisfactory solution to the perceived problem.

40. Replying to commenters that stress the need for reform, discussed above, several commenters argue that none provides evidence supporting the need for a nationwide rule at this time.[30] Ad Hoc Coalition of Southeastern Utilities states that commenters such as Exelon and Multiparty Commenters provide only anecdotes supporting their contention that there is a need to reform transmission planning and cost allocation processes, and argues that these individual issues can be addressed on a case-specific basis rather than through generic rules. Joined by Southern Companies, Ad Hoc Coalition of Southeastern Utilities argues that factual allegations of transmission expansion deficiencies are not applicable to the Southeast, pointing to their robust transmission grid. They state that, to the extent these allegations raise issues for other regions, then they should be addressed within those regions and that these issues do not merit nationwide treatment.[31] Additionally, Ad Hoc Coalition of Southeastern Utilities asserts that existing planning processes under Order No. 890 have not been in place long enough to determine whether reforms are needed, and other commenters assert that existing planning processes are

[30] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; San Diego Gas & Electric; and Southern Companies.

[31] Ad Hoc Coalition of Southeastern Utilities, Large Public Power Council and Southern Companies cite to *Associated Gas Distributors*, 824 F.2d 981 at 1019.

working well.[32] PSEG Companies assert that the real issue is the siting process, which makes it difficult to actually build projects even if they are truly needed to maintain system reliability.

41. Indianapolis Power & Light states that the Commission has not undertaken any type of analysis to find out what needs to be built, where it needs to be built, and who needs to build it. Indianapolis Power & Light asserts that the Commission has not looked closely at the different regions of the country to determine which areas could benefit from the new proposed reforms. Indianapolis Power & Light states that the Commission has not sufficiently demonstrated a need for this rulemaking and should consider whether its broad-based application is necessary in the first place. San Diego Gas & Electric recommends that the Commission not issue a Final Rule at this time, arguing that doing so based on the current proposals would disrupt and delay the build-out of the transmission grid and cause transmission providers to redirect resources away from that primary objective to the inevitable legal and compliance challenges to this Final Rule.

### C. Commission Determination

42. The Commission concludes that it is appropriate to act at this time to adopt the package of reforms contained in this Final Rule. Our review of the record, as well as the

[32] *E.g.*, PSEG Companies and Salt River Project.

recent studies discussed above, indicates that the transmission planning and cost allocation requirements established in Order No. 890 provide an inadequate foundation for public utility transmission providers to address the challenges they are currently facing or will face in the near future. Although focused on discrete aspects of transmission planning and cost allocation processes, the reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that transmission facilities in the transmission plan will move forward to construction. The Commission's actions today therefore will enhance the ability of the transmission grid to support wholesale power markets and, in turn, ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

43. The Commission acknowledges that transmission planning processes have seen substantial improvements, particularly at the regional level, in the relatively short time since the issuance of Order No. 890. Moreover, as some commenters note, transmission planning processes in many regions continue to evolve as public utility transmission providers and stakeholders explore new ways of addressing mutual needs. However, the Commission is concerned that the existing requirements of Order No. 890 regarding transmission planning and cost allocation are insufficient to ensure that this evolution will occur in a manner that ensures that the rates, terms and conditions of service by public

utility transmission providers are just and reasonable and not unduly discriminatory. As a number of commenters contend, inadequate transmission planning and cost allocation requirements may be impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development due to a lack of coordination, all of which contributes to unnecessary congestion and difficulties in obtaining more efficient or cost-effective transmission service.

44. The increase in transmission investment in recent years, as noted in the report produced by Edison Electric Institute and cited by Large Public Power Council,[33] does not mitigate our need to act at this time. To the contrary, as discussed below, the recent increase in transmission investment supports issuance of this Final Rule to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions moving forward. In its report, Edison Electric Institute states that its members have steadily increased investment in transmission over the period from 2001 to 2009, resulting in approximately $55.3 billion in new transmission facilities.[34] NERC confirms the recent increase in

[33] Large Public Power Council (citing *Edison Electric Institute report, available at* http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf).

[34] Edison Electric Institute at v.

investment in its 2010 Long-Term Reliability Assessment.[35] This trend appears to be only the beginning of a longer-term period of investment in new transmission facilities. In another report commissioned by Edison Electric Institute, Brattle Group suggests that approximately $298 billion of new transmission facilities will be required over the period from 2010 to 2030.[36] NERC's analysis of the past 15 years of transmission development confirms the significant increase in future transmission investment, showing that additional transmission planned for construction during the next five years nearly triples the average miles that have historically been constructed.[37]

45. The need for additional transmission facilities is being driven, in large part, by changes in the generation mix. As NERC notes in its 2009 Assessment, existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of

[35] NERC 2010 Assessment at 25; *see also* Brattle Group, Attachment at 4 (noting rapid increase in transmission development, from $2 billion annually in the 1990s to $8 billion annual in 2008 and 2009).

[36] Transforming America's Power Industry at 37, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf.

[37] NERC 2010 Long-Term Reliability Assessment at 25.

renewable generation.[38] NERC has identified approximately 131,000 megawatts of new generation planned for construction over the next ten years, with the largest fuel-type growth in gas-fired and wind generation resources.[39] These shifts in the generation fleet increase the need for new transmission. Additionally, the existing transmission system was not built to accommodate this shifting generation fleet. Of the total miles of bulk power transmission under construction, planned, and in a conceptual stage, NERC estimates that 50 percent will be needed strictly for reliability and an additional 27 percent will be needed to integrate variable and renewable generation across North America.[40]

46. Rather than demonstrating a lack of need for action, as claimed by some commenters, the recent increases in constructed and planned transmission facilities supports issuance of this Final Rule at this time to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions. The increased focus on investment in new transmission projects makes it even more critical to implement these reforms to ensure that the more efficient or cost-effective projects come to fruition. The record in

[38] NERC 2009 Long-Term Reliability Assessment at 8; *see also supra* P 29 (summarizing current state renewable portfolio standards).

[39] NERC 2010 Long-Term Reliability Assessment at 12.

[40] *Id.* at 24.

this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.

47. As explained below, each of the individual reforms adopted by the Commission is intended to address specific deficiencies in the Commission's existing transmission planning and cost allocation requirements. Through this package of reforms, the Commission seeks to ensure that each public utility transmission provider will work within its transmission planning region to create a regional transmission plan that identifies transmission facilities needed to meet reliability, economic and Public Policy Requirements, including fair consideration of lines proposed by nonincumbents, with cost allocation mechanisms in place to facilitate lines moving from planning to development. Although focused on particular aspects of the Commission's transmission planning and cost allocation requirements, these reforms are integrally related and should be understood as a package that is designed to reform processes and procedures that, if left in place, could result in Commission-jurisdictional services being provided at rates that are unjust and unreasonable and unduly discriminatory or preferential.

48. A number of commenters maintain that the Commission in the Proposed Rule failed to provide adequate evidence to support a finding under section 206 of the FPA

that the reforms adopted in this Final Rule are necessary to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Section 313(b) of the FPA makes Commission findings of fact conclusive if they are supported by substantial evidence.[41] When applied in a rulemaking context, "the substantial evidence test is identical to the familiar arbitrary and capricious standard."[42] The Commission thus must show that a "reasonable mind might accept" that the evidentiary record here is "adequate to support a conclusion,"[43] in this case that this Final Rule is needed "to correct deficiencies in transmission planning and cost allocation processes," as described.[44] In the legal authority sections throughout this Final Rule, the Commission discusses how the cases cited by commenters demonstrate that the Commission has met its burden.

49. Commenters that maintain that the Commission's proposal is not supported by substantial evidence demand that the Commission identify evidence that is far in excess of what a reasonable person would require. We thus disagree with such comments, including Indianapolis Power & Light's, that it is necessary for the Commission to

[41] 16 U.S.C. 825l(b).

[42] *Wisconsin Gas Co. v. FERC*, 770 F.2d 1144, 1156 (1985); s*ee also Associated Gas Distributors v. FERC*, 824 F.2d 981 at 1018.

[43] *Dickenson v. Zurko*, 527 U.S. 150, 155 (1999).

[44] Proposed Rule, FERC Stats & Regs. ¶ 32,660 at P 1.

determine what needs to be built, where it needs to be built, and who needs to build it. That is not, and is not required to be, the intent of this rulemaking. This rulemaking reforms processes and is not intended to address such questions. No commenter has contested the need for additional transmission facilities, and numerous examples have been provided here of transmission planning and cost allocation impediments to the development of such facilities. Our intent here is to continue to ensure that public utility transmission providers use just and reasonable transmission planning processes and procedures, as required by Order Nos. 888 and 890, to provide for the needs of their transmission customers. Such planning may require public utility transmission providers—in consultation with stakeholders—to determine what needs to be built, where it needs to be built, and who needs to build it, but the Commission is not making such determinations here.

50. We also reject the characterization of factual examples presented to demonstrate the need for reform as anecdotal evidence. A wide range of concerns have been raised by commenters, and the Commission need not, and should not, wait for systemic problems to undermine transmission planning before it acts. The Commission must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and investment in the right transmission facilities as the industry moves forward to address the many challenges it faces. Transmission planning is a complex process that requires consideration of a broad range of factors and an assessment

of their significance over a period that can extend from present out to 20, 30 years or more in the future. In addition, the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing. Given the need to deal with these matters over a long time horizon, it is appropriate and prudent that we act at this time rather than allowing the types of problems described above to continue or to increase. In light of these conditions and as explained below, we find that it is reasonable to take generic action through this rulemaking proceeding.

51. A brief consideration of the two cases that commenters rely on to argue that the Commission has not satisfied the substantial evidence standard helps to demonstrate that the standard has been fully met. In *National Fuel*, the court found that the Commission had not met the substantial evidence standard when it sought to extend its standards of conduct that regulate natural gas pipelines' interactions with their marketing affiliates to their interactions with their non-marketing affiliates. The court noted that it had upheld the standards of conduct as applied to pipelines and their marketing affiliates because the Commission had shown both a theoretical threat that pipelines could grant undue preferences to their marketing affiliates and evidence that such abuse had occurred.[45] In finding that the Commission had not met the substantial evidence standard when seeking to extend the standards of conduct, the court noted that the Commission had not cited a

[45] *National Fuel*, 468 F.3d 831 at 839.

single example of abuse by non-marketing affiliates. It concluded that the Commission relied either on examples of abuse or comments from the rulemaking that simply reiterated a theoretical potential for abuse.[46] The court remanded the matter and noted that if the Commission chose to proceed it could even rely solely on a theoretical threat if it could show how the threat justified the costs that the rules would create.[47]

52. Our action in this Final Rule is entirely consistent with the standards that the court set forth in *National Fuel*. We conclude that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities, and that addressing these issues is necessary to ensure just and reasonable rates. In other words, the problem that the Commission seeks to resolve represents a "theoretical threat," in the words of the *National Fuel* decision, the features of which are discussed throughout the body of this Final Rule in the context of each of the reforms adopted here. This threat is significant enough to justify the requirement imposed by this Final Rule. It is not one that can be addressed adequately or efficiently through the adjudication of individual complaints. The problems that we seek to resolve here stem from the absence of planning processes that take a sufficiently broad view of

[46] *Id.* at 841.

[47] *Id.* at 844.

both the tasks involved and the means of addressing them. Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate planning processes are in place.

53. Stated in another way, in the terminology of *National Fuel*, the remedy we adopt is justified sufficiently by the "theoretical threat" identified herein, even without "record evidence of abuse." The actual experiences of problems cited in the record herein provide additional support for our action, but are not necessary to justify the remedy.

54. *Associated Gas Distributors* likewise is distinguishable from this proceeding. In that case, the court reviewed the Commission's rationale in Order No. 436 for industry-wide contract demand adjustment conditions, which permitted pipeline customers to reduce their contract demand by up to 100 percent over a period of five years.[48] The court held that the Commission failed to develop an adequate rationale for authorizing what it characterized as the "drastic action" of 100 percent contract demand reduction, and that the reasons the Commission provided "seem[ed] peripheral to the problem the Commission set out to solve."[49] The court also found that one of the Commission's arguments while "highly relevant" to contract demand reduction, failed to support the

[48] *Associated Gas Distributors*, 824 F.2d 981 at 1013.

[49] *Id.* at 1018-19.

broad remedy the Commission adopted.[50] The court explained that it was unclear why an industry-wide solution was necessary to solve a problem that the Commission suggested applied only "to a limited portion of the industry." [51]

55. We find that the facts and findings of *Associated Gas Distributors* are in no way comparable to the matters involved in this Final Rule. We disagree with commenters that characterize our reasoning as inadequate or peripheral to the problems that the Commission has identified in this proceeding. To the contrary, the reforms adopted herein are necessary to address those problems and are supported by the reasons set forth in this Final Rule. As discussed herein, the Commission finds that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities. There is a close relationship between those problems and the Commission's actions here to identify a minimum set of requirements that must be met to ensure that transmission planning processes and cost allocation methods subject to its jurisdiction result in Commission-jurisdictional services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

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[50] *Id.* at 1019.

[51] *Id.* at 1018-19.

56. We also disagree with commenters that argue that the reforms adopted in this Final Rule will have an impact on industry that is comparable to the impact at issue in *Associated Gas Distributors*. The impact in that case involved the potential losses a gas pipeline could face from 100 percent contract demand reduction by a customer over a period of five years. Such reduction represents the complete elimination of expected revenues from gas sales under a contract. By contrast, compliance with this Final Rule will involve the adoption and implementation of additional processes and procedures. Many public utility transmission providers that are subject to this Final Rule already engage in processes and procedures of this type.

57. We acknowledge that some public utility transmission providers may need to do more than others to achieve compliance with the requirements of this Final Rule. Such differences, however, do not mean that the problems identified herein are "limited to a portion of the industry," in the terms used in *Associated Gas Distributors*. Indeed, acting on a generic basis is necessary for the Commission to identify and implement a minimum set of requirements for transmission planning processes and cost allocation methods, as discussed above.

58. We also disagree with commenters who assert that the Commission is relying on unsubstantiated allegations of discriminatory conduct or that the current Order No. 890 processes have not been in place long enough to justify the reforms proposed herein. The

courts have made clear that the Commission need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.[52] In *Associated Gas Distributors*, the court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them and that courts do not insist on empirical data for every proposition upon which the selection depends: "[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall."[53] As discussed in this Final Rule, the Commission has received many comments arguing that commenters have experienced unjust and unreasonable, or unduly discriminatory or preferential practices in the transmission planning aspects of the transmission service provided by public utility transmission providers and that the lack of guidance from the Commission has delayed, as well as hindered, transmission projects. We have an obligation under section 206 to remedy these unjust and unreasonable, or unduly discriminatory or preferential rates, terms, and conditions and practices affecting rates.

59. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 890, deficiencies in the requirements of the existing *pro forma* OATT must be remedied

[52] *TAPS v. FERC*, 225 F.3d 667 at 688; *National Fuel*, 468 F.3d 831.

[53] 824 F.2d 981 at 1008.

to support the more efficient and cost-effective development of transmission facilities used to provide Commission-jurisdictional services. Moreover, action is needed to address the opportunities to engage in undue discrimination by public utility transmission providers. Our actions in this Final Rule are necessary to produce rates, terms and conditions that are just and reasonable. We therefore exercise our broad remedial authority[54] today to ensure that rates are not unjust and unreasonable and to limit the remaining opportunities for undue discrimination.

60. We also disagree with the commenters that claim that any concerns with current transmission planning and cost allocation processes are better dealt with on a case-specific basis rather than through a generic rule. While the concerns discussed above that are driving the need for these reforms may not affect each region of the country equally, we remain concerned that the existing transmission planning and cost allocation requirements of Order No. 890 are inadequate to ensure the development of more efficient and cost-effective transmission. It is well established that the choice between rulemaking and case-by-case adjudication "lies primarily in the informed discretion of the administrative agency."[55] It is within our discretion to conclude that a generic

[54] *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967).

[55] *SEC v. Chenery Corp*., 332 U.S. 194, 203 (1947). *See also Alaska Power & Telephone Co.*, 98 FERC ¶ 61,092, at 61,277 (2002); *Trailblazer Pipeline Co.*,

(continued…)

rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry wide problems facing us.

61. Nevertheless, the Commission recognizes that each transmission planning region has unique characteristics and, therefore, this Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences. The Commission recognizes that many transmission planning regions have or are in the process of taking steps to address some of the concerns described in this Final Rule. We encourage those regions to use the objectives and principles discussed in this Final Rule to guide continued development and compel them to abide by the requirements of this Final Rule.

62. The Commission recognizes the scope of these requirements, and to that end the Commission will continue to make its staff available to assist industry regarding compliance matters, as it did after Order No. 890. As stated above, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

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79 FERC ¶ 61,274, at 62,183 (1997).

### D. Use of Terms

63. Before turning to the requirements of this Final Rule, the Commission defines several of the key terms used herein. For purposes of this Final Rule, there is a distinction between a transmission facility in a regional transmission plan and a transmission facility selected in a regional transmission plan for purposes of cost allocation. Transmission facilities selected in a regional transmission plan for purposes of cost allocation are transmission facilities that have been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs. Those may include both regional transmission facilities, which are located solely within a single transmission planning region and are determined to be a more efficient or cost-effective solution to a regional transmission need, and interregional transmission facilities, which are located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to a regional transmission need. Such transmission facilities often will not comprise all of the transmission facilities in the regional transmission plan; rather, such transmission facilities may be a subset of the transmission facilities in the regional transmission plan. For example, such transmission facilities do not include a transmission facility in the regional transmission plan but that has not been selected in the

manner described above, such as a local transmission facility or a merchant transmission facility. A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.

64. In distinguishing between transmission facilities selected in a regional transmission plan for purposes of cost allocation and other transmission facilities that also may be in the regional transmission plan, we seek to recognize that different regions of the country may have different practices with regard to populating their regional transmission plans. In some regions, transmission facilities not selected for purposes of regional or interregional of cost allocation nonetheless may be in a regional transmission plan for informational purposes, and the presence of such transmission projects in the regional transmission plan does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need, as is the case for transmission facilities selected in a regional transmission plan for purposes of cost allocation. By focusing in parts of this Final Rule on transmission facilities selected in a regional transmission plan for purposes of cost allocation, we do not intend to disturb regional practices with regard to other transmission facilities that also may be in the regional transmission plan.

65. We also clarify that the requirements of this Final Rule are intended to apply to new transmission facilities, which are those transmission facilities that are subject to

evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule. The requirements of this Final Rule will apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's filing adopting the transmission planning and cost allocation reforms of the *pro forma* OATT required by this Final Rule. We appreciate that transmission facilities often are subject to continuing evaluation as development schedules and transmission needs change, and that the issuance of this Final Rule is likely to fall in the middle of ongoing planning cycles. Each region is to determine at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the requirements of this Final Rule.[56] Our intent here is that this Final Rule not delay current studies being undertaken pursuant to existing regional transmission planning processes or impede progress on implementing existing transmission plans. We direct public utility transmission providers to explain in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule.

66. Finally, nothing in this Final Rule should be read as the Commission granting

[56] We note that existing planning processes already include specific points at which a project will no longer be subject to reevaluation.

approval to build a "transmission facility in a regional transmission plan" or a "transmission facility selected in a regional transmission plan for purposes of cost allocation." For purposes of this Final Rule, the designation of a transmission project as a "transmission facility in a regional transmission plan" or a "transmission facility selected in a regional transmission plan for purposes of cost allocation" only establishes how the developer may allocate the costs of the facility in Commission-approved rates if such facility is built. Nothing in this Final Rule requires that a facility in a regional transmission plan or selected in a regional transmission plan for purposes of cost allocation be built, nor does it give any entity permission to build a facility. Also, nothing in this Final Rule relieves any developer from having to obtain all approvals required to build such facility.

## III. Proposed Reforms: Transmission Planning

67. This section of the Final Rule has three parts: (A) participation in the regional transmission planning process; (B) nonincumbent transmission developers; and (C) interregional transmission coordination.

### A. Regional Transmission Planning Process

68. This part of the Final Rule adopts several reforms to improve regional transmission planning. First, building on the reforms that the Commission adopted in Order No. 890, this Final Rule requires each public utility transmission provider to participate in a regional transmission planning process that produces a regional

transmission plan and complies with existing Order No. 890 transmission planning principles. Second, this Final Rule adopts reforms under which transmission needs driven by Public Policy Requirements are considered in local and regional transmission planning processes. By "local" transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890. These reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers. [57] This, in turn, will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region. Each of these reforms is discussed more fully below.

69. Part A of section III has four subsections: (1) need for reform concerning regional transmission planning; (2) legal authority for transmission planning reforms;[58]

[57] As in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. We leave such decisions in the first instance to the judgment of public utility transmission providers, in consultation with stakeholders participating in the regional transmission planning process.

[58] Because the legal authority concerns raised by commenters with regard to our

(continued…)

(3) regional transmission plan and Order No. 890 transmission planning principles; and

(4) consideration of transmission needs driven by Public Policy Requirements.

### 1. Need for Reform Concerning Regional Transmission Planning

#### a. Commission Proposal

70. In the Proposed Rule, the Commission explained that, since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890's regional participation transmission planning principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. The Commission explained that, to meet that principle, each public utility transmission provider is currently required to coordinate with interconnected systems to: (1) share system plans to ensure that the plans are simultaneously feasible and otherwise use consistent assumptions and data; and (2) identify system enhancements that could relieve congestion or integrate new resources.[59] The Commission thus did not require development of a transmission plan by each transmission planning region. Moreover, the Commission did not require regional transmission planning activities to comply with the transmission planning principles established in Order No. 890.[60] As such, the

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regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together.

[59] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 45 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523).

[60] *See Entergy Services, Inc.*, 124 FERC ¶ 61,268, at P 104 (2008).

Commission proposed to require each public utility transmission provider to participate in a regional transmission planning process that satisfies the existing Order No. 890 transmission planning principles[61] and that produces a regional transmission plan.

71. The Commission also explained that, while it intended Order No. 890's economic planning studies transmission planning principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including transmission facilities to integrate new resources and loads on an aggregated or regional basis,[62] it recognized that its statements with respect to the Order No. 890 economic planning studies transmission planning principle may have contributed to confusion as to whether Public Policy Requirements may be considered in the

[61] These transmission planning principles are: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.

[62] Order No. 890's economic planning studies transmission planning principle requires that stakeholders be given the right to request a defined number of high priority studies annually through the transmission planning process, which are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources or loads on an aggregated or regional basis. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547-48.

transmission planning process.[63] The Proposed Rule stated that, when conducting transmission planning to serve native load customers, a prudent public utility transmission provider will not only plan to maintain reliability and consider whether transmission facilities or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant Public Policy Requirements. The Proposed Rule further stated that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers. The Commission also noted that providing for incorporation of Public Policy Requirements in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.[64] The Commission therefore proposed to require each public utility transmission provider to amend its OATT so that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.

**b. Comments**

72. A number of commenters support the Commission's preliminary determination in the Proposed Rule that there is a need to enhance the regional transmission planning

[63] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 55-57 & n.76.

[64] *Id.* P 63.

process.[65] In supporting the proposal to implement new regional transmission planning requirements, Pennsylvania PUC argues that the current regional transmission planning process does not lend itself to the sort of open and transparent processes that allow state commissions to fully contribute to the regional transmission planning arena. Iberdrola Renewables states that the proposed reforms would advance the sound development of substantial new renewable energy resources, which it argues is critical to the nation's energy security, economic well-being, and the environment. AWEA states that existing transmission planning processes are too parochial in design and practice, and it suggests that the proposed transmission planning reforms will remedy these deficiencies.

73. However, other commenters argue that there is no need for reform of regional transmission planning requirements, at least on a nationwide basis.[66] Ad Hoc Coalition of Southeastern Utilities and Southern Companies argue that any problems that may exist regarding regional transmission planning are local in nature and the Commission should not undertake comprehensive, generic reform. They argue that the regional transmission planning concerns expressed in the Proposed Rule are not present in the Southeast.

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[65] *E.g.*, 26 Public Interest Organizations; AWEA; Atlantic Grid; Clean Line; East Texas Cooperatives; Energy Future Coalition Group; Gaelectric; Iberdrola Renewables; Massachusetts Departments; NextEra; Pennsylvania PUC; Western Grid Group; and Wind Coalition.

[66] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Avista and Puget Sound; Bonneville Power; ColumbiaGrid; Indianapolis Power & Light; Southern Companies; and WestConnect.

ColumbiaGrid, Bonneville Power, Avista, and Puget Sound argue that regional transmission planning in the Northwest is robust. WestConnect makes a similar point regarding its collaborative planning process. Avista and Puget Sound state that the proposed reforms could threaten the continued viability of ColumbiaGrid's successful collaborative approach to planning because of concerns that some ColumbiaGrid members may not participate in that process if the Proposed Rule's reforms are adopted.

74. Others argue that the Commission should allow existing regional transmission planning processes to mature before taking action.[67] Sacramento Municipal Utility District contends that comprehensive transmission planning currently exists, planning studies are being performed, results are being evaluated, and interested stakeholders are actively engaged and, consequently, the Commission need not and should not take further action. Modesto Irrigation District states that existing regional and interconnectionwide transmission planning processes in the West provide an effective and comprehensive way to determine transmission needs and the transmission projects that efficiently address those needs in a manner that is consistent with the bottom up, stakeholder-driven

[67] *E.g.*, California Transmission Planning Group; Sacramento Municipal Utility District; and WestConnect.

transmission planning processes found in Order No. 890.[68] In reply, California Transmission Planning Group states that it agrees with commenters in the Western Interconnection that existing regional and interconnectionwide processes should continue to mature. It argues that comments expressing frustration with its planning process are indicative of the need to provide such processes time to mature, noting that its work has matured rapidly in the year since it was formed. Coalition for Fair Transmission Policy states that transmission investment has accelerated in recent years and, as a result, current transmission planning processes are working.

75. Others argue that the Proposed Rule would lead to undesirable outcomes. California Transmission Planning Group argues that the Proposed Rule would require it to transform itself from a regional coordinator of transmission studies and planning into a quasi-adjudicatory arbiter of the relative economic merits of specific transmission projects or alternatives and a gatekeeper to cost recovery and ratemaking mechanisms. California Transmission Planning Group also notes the legal constraints on many of its public agency members from assuming certain planning-related responsibilities.

[68] In describing these comments, we use the terms "interconnectionwide" and "regional" even though many commenters in the western United States used the term "regional" for interconnectionwide and "subregional" for regional. However, we will continue to use the terms "interconnectionwide" and "regional" in this Final Rule to make these comments clearer to readers outside of the West.

NorthWestern Corporation (Montana) does not believe the proposed approach is workable in the unorganized market areas in the West because the transmission provider, not the regional planning entity, has the obligation to the Commission through its tariff.

76. North Carolina Agencies argue that transmission planning must be initiated at the local and regional levels subject to state-level authority and based on the needs of customers who bear the burdens and benefits of the decisions resulting from the planning process. North Carolina Agencies also state that transmission developers who offer transmission projects as an alternative to locally planned solutions must be required to participate in and have their proposals considered as part of the relevant state planning process. Imperial Irrigation District points to potential confusion in the West, and states that it believes that the creation of a new regional transmission planning authority would impede, not hasten, transmission development.

77. However, Multiparty Commenters urge the Commission not to be swayed by arguments that reform of the transmission planning and cost allocation processes are not necessary simply because there has been an increase in transmission investment in the last few years**,** asserting that more investment does not mean that there is enough transmission being built to satisfy future needs, such as the interconnection of renewable resources. NextEra disagrees with commenters asserting that revising transmission planning procedures would disrupt existing processes under Order No. 890, arguing that those processes should be improved if there is a need to do so, as it would be wasteful to

withhold needed reforms to observe how current processes would evolve. Powerex states that, although progress has been made in transmission planning processes since Order No. 890 was issued, more reforms are needed to ensure transparency and a level playing field for all stakeholders. National Grid agrees that the Commission should not wait to exercise its authority to require improvements to transmission planning processes. 26 Public Interest Organizations argue that Southern Companies' claims that the transmission planning deficiencies identified in the Proposed Rule do not pertain to them and that implementation of the Proposed Rule would harm existing processes are unsupported by the facts and may reflect the inability of planning authorities to recognize the limits of their own procedures.

### c. Commission Determination

78. We conclude that it is necessary to act under section 206 of the FPA to adopt the regional transmission planning reforms of this Final Rule, as discussed more fully below, to ensure just and reasonable rates and to prevent undue discrimination by public utility transmission providers. Our review of the record, including the comments submitted by numerous entities representing a variety of diverse viewpoints, makes clear to us that reform is necessary at this time. Specifically, we conclude that the existing requirements of Order No. 890 are inadequate to ensure that public utility transmission providers in each transmission planning region, in consultation with stakeholders, identify and evaluate transmission alternatives at the regional level that may resolve the region's

needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers. Moreover, the existing requirements of Order No. 890 do not necessarily result in the development of a regional transmission plan that reflects the identification by the transmission planning region of the set of transmission facilities that are more efficient or cost-effective solutions for the transmission planning region.

79. As the Commission explained in the Proposed Rule, when an individual public utility transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission alternatives that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders.[69] Through this process, the public utility transmission provider evaluates the various alternatives available to determine a set of solutions that meet the system's needs more efficiently or cost-effectively than other proposed solutions. At the regional level, the Commission has relied on such processes when evaluating filings to help ensure that the recovery of costs associated with transmission facilities recovered through Commission-jurisdictional rates is just and reasonable.[70]

[69] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

[70] *See, e.g., Transmission Technology Solutions, LLC, et al. v. Cal. Indep. Sys. Operator Corp.*, 135 FERC ¶ 61,077, at P 84 (2011) (rejecting complaint regarding

(continued…)

80. In some transmission planning regions, a similar level of analysis is undertaken by public utility transmission providers at the regional level, resulting in the development of a regional transmission plan that identifies those transmission facilities that are needed to meet the needs of stakeholders in the region. This occurs, for example, in each of the existing RTO and ISO regions, which, we note, serve over two-thirds of the nation's consumers.[71] In other transmission planning regions, however, as permitted by Order No. 890, public utility transmission providers use the regional transmission planning process as a forum to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. We conclude that it is necessary to have an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively. Given the potential impact such investments could have on rates for Commission-jurisdictional service, we

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California ISO transmission planning process and stating "we find that CAISO reasonably concluded that PG&E's project is ultimately the most prudent and cost-effective solution. We find that for each of the incumbent and non-incumbent proposed projects, CAISO adequately considered lower cost alternatives, selected economically efficient solutions, accounted for more than just capital costs, and considered additional project benefits.").

[71] *See IRC Brings Value to Reliability and Electricity Markets*, *available at* http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.B00F/About.htm. As discussed in section V below, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission.

conclude it is necessary to act at this time to enhance the transmission planning-related requirements imposed in Order No. 890.

81. In the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. For example, proactive cooperation among public utility transmission providers within a transmission planning region could better identify transmission solutions to more efficiently or cost-effectively meet the reliability needs of public utility transmission providers in the region. Further, regional transmission planning could better identify transmission solutions for reliably and cost-effectively integrating location-constrained renewable energy resources needed to fulfill Public Policy Requirements such as the renewable portfolio standards adopted by many states. Similarly, the development of transmission facilities that span the service territories of multiple public utility transmission providers may obviate the need for transmission facilities identified in multiple local transmission plans while simultaneously reducing congestion across the region. Under the existing requirements of Order No. 890, however, there is no affirmative obligation placed on public utility transmission providers to explore such alternatives in the absence of a stakeholder request to do so. We correct that deficiency

in this Final Rule.

82. Based on our review of the record and comments in this proceeding, we also require each public utility transmission provider to amend its OATT to explicitly provide for consideration of transmission needs driven by Public Policy Requirements in both local and regional transmission planning processes. As the Commission noted in the Proposed Rule, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, transmission needs driven by Public Policy Requirements. While transmission planning processes in some regions have evolved to reflect compliance with Public Policy Requirements, our review of the comments indicates that some transmission planning processes do not consider transmission needs driven by Public Policy Requirements.[72] As a result, some regions are struggling with how to adequately address transmission expansion necessary to, for example, comply with renewable portfolio standards. These difficulties are compounded by the fact that planning transmission facilities necessary to meet state resource requirements must be integrated with existing transmission planning processes that are based on metrics or tariff provisions focused on reliability or, in some cases, production cost savings.

83. As the Commission explained in the Proposed Rule, consideration of Public Policy

[72] For example, PJM acknowledges in its comments that under its existing transmission planning process, it cannot build transmission to anticipate the development of future generation, including renewable energy resources, that are not associated with specific generator interconnection requests.

Requirements raises issues similar to those raised in the Commission's discussion in Order No. 890 of the economic planning studies transmission planning principle.[73] When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements.[74] Therefore, we conclude that, to avoid acting in an unduly discriminatory manner against transmission customers that serve other loads, a public utility transmission provider must consider these same transmission needs for all of its transmission customers. Moreover, given that consideration of transmission needs driven by Public Policy Requirements could facilitate the more efficient and cost-effective achievement of those requirements, we conclude the reforms adopted herein are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable.

84. Turning to the commenters opposed to these reforms, we are not persuaded by

[73] In Order No. 890, the Commission intended the economic planning studies principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources and loads on an aggregated or regional basis. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[74] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 63.

those who argue that any problems with existing transmission planning are local in nature and that the Commission should not undertake comprehensive, generic reform. As we explain above in the section on the general need for the reforms in this Final Rule, the Commission need not make specific factual findings to promulgate a generic rule to ensure rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[75] As for those commenters that argue that the Commission should allow existing regional transmission planning processes to mature before acting, we believe that the discussion above illustrates that the requirements of the *pro forma* OATT are inadequate to ensure the development of more efficient or cost-effective solutions to regional needs. As we explained in section II above, while transmission planning processes have improved since the issuance of Order No. 890, we are concerned that the existing Order No. 890 requirements regarding transmission planning, as well as cost allocation, are insufficient to ensure that the evolution of transmission planning processes will occur in a manner that ensures that the rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential. At the same time, in response to North Carolina Agencies, we do not intend our reforms to preclude the ability of states to actively plan at the local level.

[75] *See discussion supra* section II.C.

### 2. Legal Authority for Transmission Planning Reforms[76]

#### a. Commission Proposal

85. In the Proposed Rule, the Commission explained that the proposed reforms in the areas of regional transmission planning and interregional transmission coordination are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission also noted that the Proposed Rule builds on Order No. 890, in which the Commission required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process, among other things, in order to remedy opportunities for undue discrimination in the provision of transmission services.[77]

#### b. Comments

86. Several commenters argue that the Commission has adequate statutory authority to

[76] As noted above, because the legal authority concerns raised by commenters with regard to both our regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together in this section of the Final Rule.

[77] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 1-2.

undertake the planning reforms in the Proposed Rule.[78] Iberdrola Renewables contends that the Commission has a firm legal basis to adopt the proposed reforms and has already relied on its authority to require regional transmission planning efforts in Order No. 890. In response to comments arguing that the Proposed Rule oversteps the Commission's authority, Exelon states that the proposed coordination reforms are well within the Commission's statutory authority to remedy the potential for undue discrimination in transmission planning activities, citing FPA sections 205 and 206, as well as *New York v. FERC*.[79] ITC Companies' reply comments also argue that the Commission has the legal authority to implement its proposals, citing the Commission's plenary authority over interstate transmission under FPA section 201 and noting that courts have broadly defined transmission in interstate commerce due to the interconnected nature of the transmission grid. Multiparty Commenters agree that the proposed reforms are within the Commission's plenary authority, and they believe that the Proposed Rule properly identifies deficiencies in transmission planning and cost allocation, and that requirements for transmission planning and cost allocation are necessary for fully competitive wholesale markets and thus fall squarely within the Commission's jurisdiction.

87. In response to those asserting that the Commission cannot require interregional

[78] *E.g.*, Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[79] 535 U.S. 1 (2002).

agreements to coordinate planning because of section 202(a)'s voluntary coordination language, commenters assert that such arguments are contrary to precedent affirming Order Nos. 888 and 2000. Exelon notes that *Public Utility District No. 1 of Snohomish County v. FERC*,[80] which affirmed Order No. 2000, found that mandatory RTO rules did not run afoul of section 202(a). ITC Companies also assert that section 202(a) does not prohibit interregional planning agreements, contrary to some comments. Multiparty Commenters also argue that section 202 does not impose a limitation on the Commission's section 206 jurisdiction. In addition, commenters such as ITC Companies and Multiparty Commenters argue that the proposals do not preempt state jurisdiction over siting decisions. 26 Public Interest Organizations argue that the FPA requires the Commission to address identified transmission planning deficiencies.

88. Some commenters argue that the Commission may consider public policy requirements. Exelon disagrees with those asserting that the Commission cannot require public utility transmission providers to consider the impacts of public policies under federal and state laws and regulations, and argues that the Commission is not establishing an independent obligation to satisfy such public policy requirements. Exelon states that courts have consistently recognized the Commission's need to adjust its regulation under

[80] 272 F.3d 607 (D.C. Cir. 2001).

the FPA to meet the changing needs of the industry.[81] LS Power explains that the proposal regarding public policy requirements is not an effort to pursue those goals but rather to ensure that transmission service is offered at just and reasonable rates. EarthJustice argues that, contrary to commenters challenging the Proposed Rule with respect to the consideration of public policy requirements, the Commission did not propose to infringe on state jurisdiction. EarthJustice argues that there is substantial evidence to support the Commission's conclusions in the Proposed Rule.[82]

89. Some commenters, however, assert that the Commission lacks jurisdiction to mandate the transmission planning reforms included in the Proposed Rule.[83] These commenters cite to section 202(a) of the FPA, which provides that coordination and interconnection arrangements are to be left to the voluntary action of public utilities. California ISO points to *Central Iowa Power Coop. v. FERC*,[84] which held that, in light of the voluntary nature of coordination under FPA section 202(a), the Commission's

[81] Exelon (citing *New York v. FERC*, 535 U.S. 1 (2002)), *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), and *Public Util. Dist. No. 1 of Snohomish Cty v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[82] EarthJustice (citing *Louisiana Pub. Serv. Comm'n v. FERC*, 551 F.3d 1042, 1045 (D.C. Cir. 2008)).

[83] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; California ISO; ColumbiaGrid; Nebraska Public Power District; North Carolina Agencies; and Sacramento Municipal Utility District.

[84] 606 F.2d 1156 n. 36 (D.C. Cir. 1979) (*Central Iowa*).

authority under FPA section 206 does not include the authority to require modifications to an otherwise just and reasonable tariff or jurisdictional agreement simply because the Commission has concluded that alternative terms and conditions would better promote the interconnection and coordination of transmission facilities.

90. Several commenters state that the Commission's statutory authority is limited with respect to transmission siting decisions.[85] North Carolina Agencies assert that, with the exception of the Commission's limited backstop authority under FPA section 216, transmission planning and expansion fall strictly within the purview of state regulatory agencies and the Proposed Rule takes into account neither the Commission's lack of authority nor the long-standing authority of the states. Some commenters also explain that the states have authority with respect to integrated resource planning.[86]

91. Several others state that the Commission should confirm that transmission planning, even with the reforms adopted by this Final Rule, continues to be driven by the needs of load-serving entities.[87] Entities such as Ad Hoc Coalition of Southeastern Utilities, APPA, and Nebraska Public Power District point to FPA section 217(b)(4) as

[85] *E.g.*, North Carolina Agencies; Florida PSC; Illinois Commerce Commission; and Nebraska Public Power District.

[86] *E.g.*, Alabama PSC; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Florida PSC; and Commissioner Skop.

[87] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; National Rural Electric Coops; Transmission Access Policy Study Group; and APPA.

the only provision in the FPA that charges the Commission with transmission planning responsibilities, expressing concern that the proposed transmission planning reforms might be read to imply a greater focus on interests of stakeholders other than load-serving entities. National Rural Electric Coops argue that Order No. 890 struck an appropriate balance among interests and should be preserved.[88] APPA argues that the failure to address section 217 makes the Proposed Rule legally deficient. Additionally, several commenters contend the Commission's proposal is inconsistent with section 217, which they state recognizes the primacy of a franchised utility's obligation to do what is needed to fulfill its obligation to service, including the implementation of state-authorized plans for transmission construction.[89]

92. In response, ITC Companies contend that the Proposed Rule is compatible with section 217 regarding the needs of load-serving entities to fulfill their service obligations. They note that section 217 does not mandate the planning of transmission in interstate commerce based on state integrated resource plans or require that the Commission disregard the needs of renewable power producers or other generators.

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[88] Additionally, National Rural Electric Coops request that the Commission to confirm that transmission planning, even with any reforms the Commission adopts in this rulemaking, will continue to be driven in the first instance by the needs of load-serving entities. Transmission Access Policy Study Group makes a similar request.

[89] *E.g.*, Edison Electric Institute; Large Public Power Council; Nebraska Public Power; and Xcel.

93. Some commenters argue that the Commission lacks statutory authority to consider broad public policies.[90] Several commenters cite to *NAACP v. FPC*[91] for the proposition that the primary purpose of the Commission's statutory mission is to ensure reliable service at just and reasonable rates, and that Congress' direction to the Commission to act in furtherance of the public interest was not a broad license to promote the general welfare. Nebraska Public Power District and Ad Hoc Coalition of Southeastern Utilities add that the Commission has recognized this limitation in addressing its responsibility to consider environmental policy objectives under the National Environmental Policy Act.[92] PSEG Companies argue that the Commission's proposed reforms related to Public Policy Requirements are legally flawed. PSEG Companies state that the Commission's section 206 authority is not unbounded, citing to *California Independent System Operator Corp. v. FERC*,[93] where the court held that the Commission was not empowered to remove members of CAISO's board of directors under section 206. Further, PSEG Companies argue that there is no evidence to support the Commission's claims of undue

[90] *E.g.*, Southern Companies; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; and Large Public Power Council.

[91] *National Ass'n for the Advancement of Colored People v. FPC*, 425 U.S. 662 (1976).

[92] Nebraska Public Power District.

[93] 372 F.3d 395 (D.C. Cir. 2004) (*CAISO v. FERC*).

discrimination under section 206.

94. Some commenters state that the Commission has not provided enough reasoning or adequate detail for the Proposed Rule so that parties can comment meaningfully on it, as required by section 553 of the Administrative Procedure Act (APA).[94] The commenters who argue this make three basic claims. They maintain that it is unclear from the Proposed Rule: (1) whether the Commission proposes that regional and interregional plans will serve as the basis for (a) future orders requiring utilities to undertake construction consistent with the plans or (b) orders compelling utilities to defer to nonincumbent utilities in connection with the construction of transmission facilities needed for reliability purposes; (2) what public policies must be incorporated in transmission plans, or in what manner such policies should be reflected; and (3) what rate mechanism the Commission would employ to allocate costs incurred by nonincumbent transmission providers to entities with whom they have no service or contractual relationship.[95]

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[94] *E.g.*, Nebraska Public Power District Comments (citing 5 U.S.C. 553, *Florida Power & Light Co. v. U.S.*, 846 F.2d 765, 771 (D.C. Cir. 1988), *Connecticut Light and Power Co. v. NRC*, 673 F.2d 525, 530 (D.C. Cir. 1982)); Large Public Power Council; Salt River Project Comments (citing *United Mine Workers or America v. MSHA*, 407 F.3d 1250, 1259 (D.C. Cir. 2005)).

[95] *E.g.*, Large Public Power Council and Nebraska Public Power District.

95. In addition, Electricity Consumers Resource Council and the Associated Industrial Groups argue that the Proposed Rule may represent a departure from the Commission's regulations under section 35.35(i)(ii), which establishes a rebuttable presumption that "[a] project that has received construction approval from an appropriate state commission or state siting authority," applying the specified criteria, qualifies as being prudently incurred.[96] Southern Companies argue that, because the Proposed Rule did not identify what it would take to satisfy the public policy requirement, the proposal would violate the Due Process Clause's "fair notice" requirement.

96. Indianapolis Power & Light questions whether the Commission has satisfied FPA section 206 requirements, arguing that the Commission has not yet found that existing transmission planning (and cost allocation) provisions are unjust and unreasonable and that it has not "fixed" the rate or practice that it finds to be unjust and unreasonable.[97]

97. To ensure that any Final Rule will not directly or indirectly require a state or municipality to impair or violate private activity bond rules under section 141 of the Internal Revenue Code, City of Los Angeles Department of Water and Power urges the Commission to include in the Final Rule the following statement: "All regional and interregional transmission plans and cost allocation methodologies must include a

[96] 18 CFR 35.35(i)(ii).

[97] Indianapolis Power & Light (citing *Electrical Dist. No. 1 v. FERC*, 774 F.2d 490, 492-93 (D.C. Cir. 1985)).

statement that municipal and public power participants are not required to take any action that would violate or impair a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, or any successor statute or regulation." Large Public Power Council makes a similar comment. In its reply comments, APPA states that City of Los Angeles Department of Water and Power raises a practical and legal issue regarding the participation of public power systems in transmission planning and cost allocation activities, and APPA agrees that the statement suggested by City of Los Angeles Department of Water and Power would foster public power systems' participation in such processes.

98. Nebraska Public Power District states that as long as it participates in regional and interregional transmission planning through the SPP, it is able to commit to enter into regional planning through the SPP tariff, but cannot make such commitments outside of its present RTO membership. Nebraska Public Power District states that it is unclear what commitments may be called for in any transmission planning agreements, such as whether these agreements: (1) will carry with them specified or unanticipated liability; and/or (2) may include an obligation to defer to regional or interregional transmission plans that could, in Nebraska Public Power District's judgment, interfere with what must be done to remain compliant with state law.

### c. Commission Determination

99. We conclude that we have authority under section 206 of the FPA to adopt the

reforms on transmission planning in this Final Rule. These reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Moreover, these reforms build on those of Order No. 890, in which the Commission reformed the *pro forma* OATT to, among other things, require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. As we explained in Order No. 890, we found that the existing *pro forma* OATT was insufficient to eliminate opportunities for undue discrimination, including such opportunities in the context of transmission planning.[98] We conclude that the reforms adopted in this Final Rule are necessary to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. We note that no party sought judicial review of the Commission's authority under Order No. 890 to adopt those reforms that we seek to enhance and improve upon here.

[98] *See, e.g.*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.

100. We disagree that section 202(a) of the FPA precludes us from adopting the transmission planning reforms contained in this Final Rule. Section 202(a) reads, in relevant part, as follows:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. . . .[99]

Section 202(a) requires that the interconnection and coordination, i.e., the coordinated operation, of facilities be voluntary. That section does not mention planning, and nothing in it can be read as impliedly establishing limits on the Commission's jurisdiction with respect to transmission planning.

101. Transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The transmission planning process itself does not create any obligations to interconnect or operate in a certain way. Thus, when establishing transmission planning process requirements, the Commission is in no way mandating or otherwise impinging upon matters that section 202(a) leaves to the voluntary action of public utility transmission providers. As we discuss herein, section 202(a) refers to the coordinated operation of facilities.

[99] 16 U.S.C. 824(a).

102. Several commenters who argue that section 202(a) prohibits our proposal rely primarily on *Central Iowa* for support.[100] In *Central Iowa*, a party argued that the Commission should have used its authority under section 206 of the FPA to compel greater integration of the utilities in the Mid-Continent Area Power Pool (MAPP) than MAPP members had proposed. In seeking this goal, the party in question sought to have the Commission require MAPP participants "to construct larger generation units and engage in single system planning with central dispatch."[101] The court held that given "the expressly voluntary nature of coordination under section 202(a)," the Commission was not authorized to grant that request.[102]

103. The court in *Central Iowa* was thus presented with a request that the Commission require an enhanced level of, or tighter, power pooling. Section 202(a) was relevant to the problem at issue in *Central Iowa* because the operation of the system through power pooling is its central subject matter. We, on the other hand, are focused in this proceeding on the transmission planning process, which is distinct from any specific system operations. Nothing in this Final Rule is tied to the characteristics of any specific form of system operations, and nothing in it requires any changes in the way existing operations are conducted. This Final Rule simply requires compliance with certain

[100] *E.g.*, ColumbiaGrid; Sacramento Municipal Utility District; and California ISO.

[101] *Central Iowa*, 606 F. 2d 1156 at 1166.

[102] *Id.* at 1168.

general principles within the transmission planning process regardless of the nature of the operations to which that process is attached. The court's interpretation of section 202(a) with respect to system operations is therefore irrelevant here.

104. Commenters point to dicta in *Central Iowa* based on section 202(a)'s legislative history that, they state, suggests that Congress intended that any coordination by public utilities with respect to transmission planning be voluntary. *Central Iowa* cites to, but does not quote directly, the legislative history to support the conclusion that "Congress was convinced that 'enlightened self-interest' would lead utilities to engage voluntarily in power planning arrangements, and it was not willing to mandate that they do so."[103] The language from the legislative history is as follows:

> The committee is confident that enlightened self-interest will lead the utilities to cooperate with the commission and with each other in bringing about the economies which can alone be secured through the planned coordination which has long been advocated by the most able and progressive thinkers on this subject.[104]

105. In response, we note that section 202(a) does not mention the transmission planning process, and nothing in that section causes one to conclude that it was intended to address the transmission planning process that is the subject of this proceeding. There

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[103] *Id.*

[104] *See Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (citing S.Rep.No.621, 74th Cong., 1st Sess. 49).

is thus no basis to resort to legislative history for further clarification.[105] Moreover, even if resorting to legislative history was appropriate in this context, we note that this passage from the legislative history also does not refer to the transmission planning process that is the subject of this Final Rule. Instead, the legislative history refers to "planned coordination," i.e., to the pooling arrangements and other aspects of system operation that are the underlying focus of section 202(a). It is in this sense that *Central Iowa* must be understood when it refers to engaging "voluntarily in power planning arrangements." The "planned coordination" mentioned in the legislative history cited in *Central Iowa* means "planned coordination" of the operation of facilities, not the planning process for the identification of transmission facilities. In short, neither *Central Iowa* nor the legislative history cited in that case involves or applies to the planning process for transmission facilities. Rather they deal with the coordinated, i.e., shared or pooled, operation of facilities after those facilities are identified and developed. By contrast, this Final Rule deals with the planning process for transmission facilities, a separate and distinct set of activities that occur before the operational activities that are the underlying focus of section 202(a).

106. Similarly, section 202(a) has no bearing on whether the Commission can mandate

[105] *See, e.g., Connecticut Nat'l Bank v. Germain*, 503 U.S. 249, 253-54 (1992) ("[I]n interpreting a statute a court should always turn first to one, cardinal canon before all others. We have stated time and again that courts must presume that a legislature says in a statute what it means and means in a statute what it says there." (citations omitted)).

requirements on regional and interregional cost allocation. The cost allocation requirements of this Final Rule do not mandate that any entity engage in any interconnection or coordination of facilities in contravention of the requirement in section 202(a) that these matters be left to the voluntary decisions of the entities in question. Section 202(a) does not address matters involved in cost allocation.

107. We acknowledge that there is longstanding state authority over certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule, like those of Order No. 890, are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

108. We disagree with the commenters who argue that this Final Rule is inconsistent

with or precluded by, or legally deficient for failing to rely on, section 217 of the FPA.[106] Our approach in this Final Rule is to build on the requirements of Order No. 890 of ensuring open and transparent transmission planning processes to evaluate proposed transmission projects, a goal that does not conflict with FPA section 217. Indeed, we believe that this Final Rule is consistent with section 217 because it supports the development of needed transmission facilities, which ultimately benefits load-serving entities. The fact that this Final Rule serves the interests of other stakeholders as well does not place it in conflict with section 217. We thus cannot agree with Ad Hoc Coalition of Southeastern Utilities that we should ensure that our transmission planning and cost allocation reforms give systematic preference to any particular set of interests. Section 217 does not require this result. It only requires that we use our authority in a way that facilitates planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. We have indicated that we will follow a flexible approach that accommodates the needs and characteristics of particular regions, and we are confident that this approach can address the needs of load-serving entities in

[106] Section 217(b)(4) of the FPA specifies that: "The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs." 16 U.S.C. 824q(b)(4).

the Southeast and elsewhere.

109. We also disagree with commenters who argue that we lack jurisdiction to require the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process. In requiring the consideration of transmission needs driven by Public Policy Requirements, the Commission is not mandating fulfillment of those requirements. Instead, the Commission is acknowledging that the requirements in question are facts that may affect the need for transmission services and these needs must be considered for that reason. Such requirements may modify the need for and configuration of prospective transmission facility development and construction. The transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.

110. Our disagreement with commenters on this point can be best explained by considering the case that they use to support their arguments, *NAACP v. FPC.* In that case, the Court found that the Commission did not have power under the FPA or the Natural Gas Act (NGA) to construe its obligation to promote the public interest under those statutes as creating "a broad license to promote general public welfare."[107]

[107] *NAACP v. FERC*, 425 U.S. 662 at 668.

Specifically, the Court found that the Commission's duty to promote the public interest under the FPA and NGA "is not a directive to the Commission to seek to eradicate discrimination," and it thus did not authorize the Commission to promulgate rules prohibiting the companies it regulates from engaging in discriminatory employment practices merely because the statutes pertain to matters affected with a public interest.[108] The Commission is doing nothing analogous when specifying that transmission needs driven by Public Policy Requirements be taken into account in the transmission planning process.

111. Requiring the development of a regional transmission plan that considers transmission needs driven by Public Policy Requirements cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA. Public Policy Requirements can directly affect the need for interstate transmission facilities, which are squarely within the Commission's jurisdiction. Moreover, we are not specifying the Public Policy Requirements that must be considered in individual local and regional transmission planning processes.[109] This further confirms that, in requiring that the transmission planning process include the evaluation of potential solutions to identified transmission needs driven by Public Policy

[108] *Id.* at 670.

[109] *See infra* section III.A.4.

Requirements, the Commission is simply requiring the consideration of facts that are relevant to the transmission planning process. In doing so, it is neither pursuing nor enforcing any specific policy goals.

112. Other commenters cite *CAISO v. FERC* for the proposition that the Proposed Rule extends beyond our authority under the FPA. In that case, the court found that the Commission did not have authority under section 206 of the FPA to direct the California ISO to alter the structure of its corporate governance, concluding that the choosing and appointment of corporate directors is not a "practice … affecting [a] rate" within the meaning of the statute.[110] The court explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and "not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so."[111] Unlike the corporate governance matters at issue in that proceeding, the transmission planning activities that are the subject of this Final Rule have a direct and discernable affect on rates. It is through the transmission planning process that public utility transmission providers determine which transmission facilities will more efficiently or cost-effectively meet the needs of the region, the development of which directly impacts the rates, terms and conditions of jurisdictional service. The rules

[110] *CAISO v. FERC*, 372 F.3d 395 at 403.

[111] *Id.*

governing the transmission planning process are therefore squarely within our jurisdiction, whether the particular transmission facilities in question are planned to meet reliability needs, address economic considerations, or meet transmission needs driven by a Public Policy Requirement.

113. We disagree with the commenters who argue that the Proposed Rule does not comply with the APA because the Proposed Rule does not provide enough reasoning or adequate detail to permit parties to comment meaningfully on it. Section 553(b)(3) of the APA requires that a notice of proposed rulemaking contain "either the terms or substance of the proposed rule or a description of the subjects and issues involved."[112] The purpose of the requirement is to ensure that "persons are 'sufficiently alerted to likely alternatives' so that they know whether their interests are 'at stake.'"[113] Courts have held in this connection that a "[n]otice of proposed rulemaking must be sufficient to fairly apprise interested parties of the issue involved. . . , but it need not specify every precise proposal which [the agency] may ultimately adopt as a rule."[114] We disagree with commenters arguing that this requires us to identify the issues that might be raised in future orders by the Commission should disputes arise as to the construction of

[112] 5 U.S.C. 553(b)(3).

[113] *Spartan Radiocasting Co., v. FCC*, 619 F.2d 314, 321 (4th Cir. 1980) (citing *South Terminal Corp. v. EPA*, 504 F.2d 646, 659 (1st Cir. 1974)).

[114] *Id.* 321-22 (citing *Consolidation Coal Co. v. Costle*, 604 F.2d 239, 248 (4th Cir. 1979)).

transmission facilities in the regional transmission planning process. This Final Rule is focused on ensuring that there is a fair regional transmission planning *process*, not substantive outcomes of that process.

114. We disagree with Southern Companies' argument that the Proposed Rule violated the fair notice requirement of the Due Process Clause because it did not identify how the Public Policy Requirements in the transmission planning process would be satisfied. As explained above, fair notice requires that we apprise parties of the issues involved. In this respect, all interested parties have had fair notice and an opportunity to comment on the Commission's proposed requirement regarding the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process and to provide their perspectives, consistent with the notice and comment requirements of the APA. Moreover, the case that Southern Companies cite in support of their argument, *Trinity Broadcasting of Fla., Inc. v. FCC*,[115] is not on point. That case involved a denial by the Federal Communications Commission (FCC) of an application to renew a commercial television broadcast license that could have been renewed under a statutory preference in favor of minority-controlled firms. A majority of the applicant's board was made up of members of minority groups, but the FCC denied the application because the applicant had not satisfied its interpretation of minority control as *de facto* or "actual"

[115] 211 F.3d 618, 628 (D.C. Cir. 2000) (*Trinity Broadcasting*).

control of operations. The court found that the agency had not given sufficient notice of its interpretation of minority control to justify punishment in the form of denial of the application. Nothing analogous is occurring here. *Trinity Broadcasting* did not involve a rulemaking proceeding, as is the case here, but rather an adjudication that raised the issue of "[w]hat constitutes sufficiently fair notice of an agency's interpretation of a regulation to justify punishing someone for violating it?"[116] A rulemaking such as the present proceeding does not involve the assessment of penalties for failure to comply with a particular regulation, and therefore the notice that is required before penalties can be assessed has no relevance here.

115. We also disagree that this Final Rule may represent a departure from section 35.35(i)(ii) of the Commission's regulations, which establishes a rebuttable presumption that a transmission project that has received construction approvals from relevant state regulatory agencies satisfies Order No. 679's[117] requirement that the transmission project is needed to ensure reliability or reduce the cost of delivered power by reducing congestion. The rebuttable presumption of prudent investment provided for in section 35.35(i)(ii) applies only to Commission determinations with respect to incentive-based

[116] *Trinity Broadcasting*, 211 F.3d 618 at 619.

[117] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

rate treatments for investment in transmission infrastructure. The Proposed Rule does not "represent a departure" from this provision because the provision deals with matters that are not covered or affected by the Proposed Rule. Electricity Consumers Resource Council and Associated Industrial Groups therefore have not adequately explained why they believe the Proposed Rule represented such a departure.

116. With respect to Indianapolis Power & Light's assertion that the Commission has failed to satisfy FPA section 206, we conclude that we have met section 206's burden. Our review of the record demonstrates that existing transmission planning processes are unjust and unreasonable or unduly discriminatory or preferential. Specifically, we conclude that the record shows that, for the *pro forma* OATT (and, consequently, public utility transmission providers' OATTs) to be just and reasonable and not unduly discriminatory or preferential, it must be revised in the context of transmission planning to include the requirement that regional transmission planning processes result in the production of a regional transmission plan using a process that satisfies the specified Order No. 890 transmission planning principles and that provides an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that these reforms satisfy the section 206 standard because they help ensure just and reasonable rates and remove those remaining opportunities for undue discrimination.

117. Finally, with respect to the concerns raised by City of Los Angeles Department of Water and Power, APPA, Nebraska Public Power District, and others regarding the legal

issues associated with public power participation in the regional transmission planning processes, we make the following observations. First, as discussed in the section of this Final Rule addressing reciprocity, we reiterate that this Final Rule simply applies the reciprocity principles set forth in Order Nos. 888 and 890 regarding non-public utility transmission provider participation in transmission planning processes. Second, non-jurisdictional entities, unlike public utilities, may choose whether to join a regional transmission planning process and, to the extent they choose to do so, they may advocate for those processes to accommodate their unique limitations and requirements.

### 3. Regional Transmission Planning Principles

#### a. Commission Proposal

118. The Proposed Rule would require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that meets the following transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies. This proposal did not include two of the Order No. 890 transmission planning principles, namely the cost allocation transmission planning principle and the regional participation transmission planning principle. More specifically, the Commission would require that each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission

plan that identifies the transmission facilities that more efficiently or cost-effectively meet the needs of public utility transmission providers, their customers and other stakeholders.[118]

119. The Proposed Rule also would provide that a merchant transmission developer that does not seek to use the regional cost allocation process would not be required to participate in the regional transmission planning process, although such a developer would be required to comply with all reliability requirements applicable to transmission facilities in the transmission planning region in which its transmission project would be located.[119] To reiterate, merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates. The Proposed Rule states that such a merchant transmission developer would not be prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.[120]

**b. Comments**

120. Many commenters agree that the Commission should require public utility transmission providers to produce a regional transmission plan using a process that

[118] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

[119] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

[120] *Id.* P 99.

complies with the Order No. 890 transmission planning principles.[121] NextEra supports the Commission's proposal provided that a regional transmission planning process produces a regional transmission plan with identified transmission facilities to be built in the near-term. Iberdrola Renewables contends that the current piecemeal, generation-driven approach to transmission development is inefficient and ineffective and hinders development of renewable energy resources. Duke states that it supports the requirement that a regional transmission plan be produced through a regional transmission planning process. Maine PUC believes that in New England, the distinction between different types of transmission projects (i.e., reliability and market efficiency transmission facilities) has impeded the development of transmission facilities that would reduce congestion costs and provide greater access to low-cost supply, including renewable resources, and suggests that the Commission consider eliminating this distinction.

121. Most commenters addressing the proposed transmission planning reforms support the Commission's proposal to require public utility transmission providers to adopt several of the Order No. 890 transmission planning principles for the regional

[121] *E.g.*, Anabaric and PowerBridge; AWEA; City and County of San Francisco; DC Energy; Duke; Duquesne Light Company; East Texas Cooperatives; Energy Future Coalition Group; LS Power; MISO; National Grid; NEPOOL; New England States' Committee on Electricity; New England Transmission Owners; NextEra; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Wilderness Society and Western Resource Advocates; and Wisconsin Electric Power Company.

transmission planning process.[122] Some commenters ask the Commission to clarify that the existing Order No. 890 transmission planning principles would remain applicable to regional transmission planning processes.[123] Some commenters also seek clarification that individual transmission owners must comply with Order No. 890 transmission planning principles and have an OATT Attachment K on file with the Commission.[124] Transmission Dependent Utility Systems state that transmission owners must comply with Order No. 890 transmission planning principles even if they are planning local transmission projects in an RTO.

122. Several supporting the Proposed Rule stress that fair process, transparency, and robust stakeholder participation are important components of the transmission planning process.[125] PPL Companies state that all interested parties, especially those that may be allocated costs for a particular transmission project, should have an opportunity to provide meaningful input into the regional transmission planning process, and urge the Commission to require that historical and real-time data be made available to interested

[122] *E.g.*, ISO New England and SPP.

[123] *E.g.*, East Texas Cooperatives and Champlain Hudson.

[124] *E.g.*, Transmission Dependent Utility Systems and Old Dominion.

[125] *E.g.*, PPL Companies; DC Energy; Direct Energy; 26 Public Interest Organizations; Green Energy and 21st Century; Western Independent Transmission Group; City of Santa Clara; Natural Resources Defense Council; New Jersey Division of Rate Counsel; and Iberdola Renewables.

stakeholders. Transmission Dependent Utility Systems contend that transmission customers need to play an integral role in the regional transmission planning process. 26 Public Interest Organizations, Green Energy and 21st Century, and Western Independent Transmission Group state that transparency in transmission planning and access to models and data are critical to nonincumbent resources and grid infrastructure providers if these entities are to be effective participants in regional transmission plan development. Independent Energy Producers Association urges the Commission to emphasize that the openness, transparency, and inclusiveness criteria of Order No. 890 should apply to all phases of the transmission planning process. New Jersey Board suggests that transmission providers be required to state the baseline methodology on which load forecasts are based. However, Anbaric and PowerBridge suggest consideration of internal procedures to treat transmission project information as confidential, including protections to ensure that transmission projects that are not selected in the regional transmission plan will remain confidential.

123. Some commenters also address dispute resolution issues in the regional transmission planning process. City of Santa Clara believes that transmission planning processes should include an effective and meaningful dispute resolution process, including the ability to request Commission resolution of unresolved disputes. Transmission Access Policy Study Group argues that guidance from the Commission is needed to ensure that the dispute resolution process is useful, suggesting that use of

reasonable, nondiscriminatory criteria to minimize the potential for discriminatory results, particularly with regard to the inclusion or exclusion of project proposals in a regional transmission plan and the consideration of public policy objectives in the transmission planning process. Transmission Access Policy Study Group suggests that the Commission establish a backstop dispute resolution or expedited complaint process to have a forum for addressing disputes regarding transmission projects selected or not selected in regional transmission plans.

124. Some commenters recommend that the Commission continue to recognize regional flexibility with respect to transmission planning processes.[126] Kansas City Power & Light and KCP&L Greater Missouri supports the Proposed Rule's suggestion that the Commission would defer to each region to develop transmission planning processes that address regional needs, noting that each region has developed differently and that not all regions are at the same level of maturity. Northern Tier Transmission Group states that the Commission should provide flexibility as to the manner in which regional plans are produced, emphasize expected results rather than process, and clarify that the region may continue to rely on a "bottom-up" process in developing the plan. SPP recommends that transmission planning authorities be permitted to develop, through their stakeholder processes and in consultation with state regulatory commissions,

[126] *E.g.*, Kansas City Power & Light and KCP&L Greater Missouri; Edison Electric Institute; and WIRES.

strategies and metrics to achieve region-appropriate compliance with the Final Rule.

125. Many entities that support the Proposed Rule believe that the regional transmission planning process in which they participate already satisfies the proposed requirements.[127] ISO/RTO Council asks that the Final Rule reflect that ISOs and RTOs already satisfy the requirements and that no further demonstration or tariff language be required in a future compliance filing with the exception of any new or altered requirements imposed by the Final Rule. In response, 26 Public Interest Organizations agree that the proposed reforms should not modify or interfere with progress being made by transmission planners with transmission planning processes that comply with or exceed Order No. 890 requirements and that only those tariff provisions that are affected by the Final Rule need to be filed.

126. On the other hand, Iberdrola Renewables states that the Commission should make clear that reliance on existing institutions and approaches would be adequate only if they can effectively implement the Commission's goals of driving needed transmission infrastructure investment. To that end, it states that in areas not covered by RTOs or ISOs, new regional agreements would be needed to ensure that the transmission providers

[127] *E.g.*, Bonneville Power; Duke; Massachusetts Departments; California ISO; Sunflower and Mid-Kansas; MISO Transmission Owners; California Commissions; MISO; New England States' Committee on Electricity; Indianapolis Power & Light; Northeast Utilities; ISO New England; New York ISO; Southern Companies; and Long Island Power Authority.

in the region have a governance structure for undertaking the regional and interregional transmission planning obligations and a workable mechanism for sharing costs consistent with the cost allocation guidelines, and clarify the factors it would consider in determining whether a particular regional proposal or compliance filing has sufficiently broad regional support to merit any deference.

127. Some commenters ask the Commission to clarify the term "transmission planning region" as it relates to the requirements of the Proposed Rule.[128] Indianapolis Power & Light and Powerex ask the Commission to define "region" in a Final Rule and include a definition of transmission planning region in whatever regulations are promulgated. California Municipal Utilities state that they believe regional consolidation of transmission planning regions should not be forced and that more detail is needed from the Commission for its members to determine if current transmission planning processes meet the requirements of the Proposed Rule. Solar Energy Industries and Large-scale Solar contend that the Commission should ensure that, on the review of compliance filings, the scope of the self-selected planning regions does not create inadvertent planning seams that inhibit the development of transmission projects needed to meet public policy requirements established by state or federal laws or regulations.

128. Several commenters urge the Commission to clarify that existing ISOs and RTOs

[128] *E.g.*, NextEra; Clean Line; California Municipal Utilities; American Transmission; and Arizona Corporation Commission.

are considered regions for purposes of transmission planning.[129] However, ITC Companies state that RTO boundaries are not always the right ones for transmission planning, and ITC Companies are concerned that, given the focus of RTOs on developing and running energy markets, it might be difficult for RTOs to plan transmission from a truly independent perspective. Instead, ITC Companies suggest that the planning function be split off from the market function so that there is a truly independent planning authority. In reply, California ISO argues that ITC Companies' recommendation is tantamount to mandating the creation of new entities, which it argues the Commission cannot do. AWEA asks the Commission to clarify that more than one organized market could form a single region for transmission planning and cost allocation purposes.

129. Commenters express different views on defining transmission planning regions outside of the ISO and RTO context. MISO Transmission Owners suggest that, where ISOs or RTOs do not exist, the Commission should allow each transmission provider to propose its own definition of what it considers its transmission planning region. Further, they state that the Commission should not define the term "transmission planning region" to be any larger or broader than an RTO or ISO region. MISO states that public utility transmission providers not associated with existing RTOs should either be required to form transmission regional planning areas with each other or participate in regional

[129] *E.g.*, ISO/RTO Council; California ISO; MISO Transmission Owners; Indianapolis Power & Light; and NextEra.

transmission planning with an adjacent RTO. Some commenters ask the Commission to determine that, in non-RTO regions, a single transmission provider or utility family cannot serve as a transmission planning region.[130] Transmission Access Policy Study Group urges the Commission to specify that transmission planning regions in areas outside of RTOs include at least two transmission providers and be at least as large as the smaller of a state or one of NERC's Regional Entities. NextEra suggests that, in non-RTO areas, geographic scope should be determined by factors such as the level of interconnections between utilities, power flows, boundaries of existing NERC regions, and historical coordination practices.

130. Ad Hoc Coalition of Southeastern Utilities claim that the Proposed Rule makes several incorrect statements concerning what constitutes a region for transmission planning purposes in the Southeast.[131] They note that the Proposed Rule references both regional and interregional organizations and processes (including NERC regional entities) as being regional for purposes of the Proposed Rule and assert that a holding that only RTO regions are sufficiently encompassing to meet the proposed requirements would be arbitrary and capricious. Given that the Commission has previously recognized

[130] *E.g.*, AWEA; Clean Line; G&T Cooperatives; Integrys; and NextEra.

[131] In reply comments, South Carolina Office of Regulatory Staff state that it concurs with Ad Hoc Coalition of Southeastern Utilities' views regarding the uniqueness of transmission planning in the Southeast.

that the South Carolina Regional Transmission Planning (SCRTP) process complies with Order No. 890, and as such is a "regional transmission planning process," South Carolina Electric & Gas asks the Commission to clarify that the SCRTP constitutes a "regional transmission planning process" as contemplated by the Proposed Rule. Colorado Independent Energy Association supports the designation of WestConnect as a regional transmission planning organization for the purposes of transmission planning and development in Colorado and to make findings to that effect in this Final Rule. Florida PSC and Commissioner Skop argue that if the Commission adopts a definition of "region" that does not recognize Florida as a distinct transmission planning region, and Florida becomes part of a multistate region, then it is unclear what role the Florida PSC would retain, if any, over the transmission planning and cost allocation processes in Florida.[132]

131. Many commenters recommend that transmission providers should evaluate both transmission and non-transmission solutions during the regional transmission planning process.[133] 26 Public Interest Organizations and Dayton Power and Light assert that

[132] Additionally, Florida PSC and Commissioner Skop express concern about the lack of Florida-based commenters, noting that either Florida utilities joined a broader coalition of commenters or, as in the case of NextEra, did not comment from the perspective of its Florida-based utility. Florida PSC and Commissioner Skop ask the Commission to take the lack of Florida-specific points of view into account when it considers its proposals.

[133] *E.g.*, AWEA; California Commissions; Wisconsin Electric; Omaha Public

(continued…)

consideration of non-transmission solutions with all other resource options is needed to determine the most cost-effective way to meet grid needs. 26 Public Interest Organizations ask the Commission to establish minimum requirements for: what types of resources should be assessed; how assessments should be conducted; and what types of modeling and sensitivity analyses are needed to estimate and compare the costs and benefits of option, implementation timelines, and relative risks of various resource choices. New Jersey Board believes that transmission providers should provide peak load reduction data that demonstrate the effect of demand response and energy efficiency on baseline forecasts. MISO supports the consideration of non-traditional solutions so long as this process does not interfere with state authority over integrated resource planning. Western Grid Group and Pattern Transmission suggest that resource planning and transmission planning should be reintegrated.

132. On the other hand, Ad Hoc Coalition of Southeastern Utilities states that a requirement for regional transmission planning processes to consider both transmission and non-transmission solutions is inconsistent with transmission planning procedures in the Southeast. It explains that non-transmission solutions are typically considered in integrated resource planning and request for proposal processes during the current "bottom-up" transmission planning process. It states that including a generation resource

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Power District; Dayton Power and Light; Eastern Environmental Law Center; Environmental NGOs; NRG; Vermont Electric; EarthJustice; and SPP.

as an alternative during the regional transmission planning process would convey a right of generation planning to the Commission that would be inconsistent with state law. Accordingly, it states that there are no transmission planning gaps in the Southeast that the Commission needs to address. In its reply comments, Ad Hoc Coalition of Southeastern Utilities argues that such a policy would be inappropriate because there would be winners and losers in any given state, such a "top-down" process would risk losing the emphasis on consumers that currently exists in the state-regulated processes. Ad Hoc Coalition of Southeastern Utilities, in responding to comments by Western Grid Group and Pattern Transmission, argues that transmission planning and resource planning in the Southeast have not diverged and that further reforms are unnecessary. Southern Companies agree.

133. MISO Transmission Owners ask the Commission to provide additional guidance regarding the meaning of "non-transmission solutions" and which of these solutions transmission providers are required to include in their transmission planning processes. MISO Transmission Owners state that if non-traditional solutions must be considered, then the Commission should clarify that they are required to participate in the transmission planning process on a similar basis as transmission projects.

134. Other commenters ask for clarification and guidance from the Commission on other transmission planning-related issues associated with the Proposed Rule. WIRES believes that the Commission should consider additional rules that promote consistent

transmission planning cycles, stakeholder procedures, action timelines, and criteria for evaluating project proposals. Transmission Access Policy Study Group also suggests that the Commission require regular updating of regional transmission plans, and require jurisdictional transmission providers to file, for public comment, a "planning report card" identifying the projects proposed during the transmission planning process, the projects approved and included in the regional transmission plan, and the projects that were proposed but excluded from the plan and the reasons those proposed projects were rejected. Transmission Access Policy Study Group states that the Final Rule should subject decisions as to which facilities are included in a regional transmission plan to justification and objective evaluation to prevent discrimination and unjust and unreasonable rates.

135. AEP asserts that a significant flaw in typical transmission planning processes is the failure to consider benefits beyond the near-term. Therefore, AEP recommends that the Commission direct each transmission planning region to develop a long-term plan that utilizes a 20-30 year planning horizon in the determination of need analysis (while still permitting RTOs to annually evaluate shorter-term projects needed to complement the long-term plan). AEP argues that the useful life of any transmission facility is likely to exceed 40 years and, consequently, the most efficient transmission planning process should cover a minimum span of 20 years, and cites to SPP's and California ISO's transmission planning processes, which use 20-year planning horizons.

136. Primary Power supports the concept that every transmission provider must participate in a regional transmission planning process where specific projects are determined to be in the public convenience and necessity, and urges the Commission to devise threshold requirements ensuring that transmission planners have a degree of independence from market participants that would promote equitable and economically supportable results in terms of which transmission facilities are built and who ultimately pays for them. Some commenters also ask the Commission to clarify that least-cost planning is a driver of the transmission planning process. Transmission Dependent Utility Systems state that both the regional and interregional transmission planning processes adopted by the Final Rule should include clarification that coordination of reliability and economic transmission planning includes identifying optimal solutions to congestion for all transmission customers and load-serving entities across the region. Transmission Dependent Utility Systems recommend that the Commission clarify this concept in the Final Rule and explicitly recognize a joint optimization requirement.

137. Solar Energy Industries and Large-scale Solar suggest that the Commission require holistic long-term planning on a regional basis, in which the interaction of proposed projects with other projects across the region, as well as the integration of renewable resources, distributed generation, and demand response is considered. Transmission Agency of Northern California asks the Commission to clarify that a regional transmission planning "process" need not be narrowly defined as participation in

a single set of procedures and that the transmission planning process need not serve every planning purpose. Arizona Corporation Commission seeks clarification on who would determine whether a transmission project is a reliability project within the context of the regional transmission planning process. Arizona Corporation Commission suggests that state-level entities, such as state utility commissions, should continue to determine whether a transmission project is a reliability project during line siting and/or determination of need proceedings. Additionally, it states that all proposed transmission projects should be freshly evaluated in each transmission planning cycle so that projects are aligned with transmission needs at the time and adequately incorporate current public policy requirements.

138. Some commenters seek assurance from the Commission that the needs of states and load-serving entities would be considered in the regional transmission planning process. NARUC states that the Final Rule should identify the states as key players in any transmission planning process, pointing to the primary role of states in transmission siting. E.ON emphasizes that the Commission should work to ensure that the Final Rule's planning requirements not give rise to new impediments to a local transmission owning utility's ability to efficiently satisfy customer needs under state service obligations. E.ON suggests that the Commission incorporate the following requirements in its Final Rule: regional and interregional transmission planning processes should be sufficiently flexible to accommodate the real-time requirements of a transmission owner

and operator's native load customers; and the transmission planning process should recognize that the obligation to serve still exists in a number of jurisdictions and that any regional plan or process needs to allow for the fact that it is that obligation that drives transmission planning.

139. Others are concerned about the applicability of the Proposed Rule to currently pending transmission projects. Atlantic Wind Connection seeks clarification that sponsored projects with a pending request for inclusion in a regional transmission plan should be studied under the requirements of the Final Rule without undue delay, including delays resulting from any proposed procedural requirements. Edison Electric Institute argues that the Final Rule should apply to projects only on a going-forward basis, and a project identified in an existing plan should not be subject to bumping in a revised transmission planning process filed in compliance with a Final Rule. Northeast Utilities states that the Final Rule should avoid harming projects already included in the transmission planning process.

140. Some commenters ask the Commission to establish a funding mechanism to allow interested parties that are not market participants to fully participate in the regional transmission planning process. 26 Public Interest Organizations assert that an essential element of robust and broadly supported regional planning is the participation of non-market participants and that this requires ongoing provider assistance. They state that, because non-market stakeholders have neither the financial resources nor staff expertise

to participate effectively in regional transmission plan development processes without special assistance, the Commission should direct transmission providers to facilitate participation of these stakeholders through a funding mechanism to cover reasonable technical assistance and other participation costs. They conclude that these costs can be rolled into the rates of the transmission service providers. Western Grid Group offers suggestions as to how a funding mechanism could be implemented. Additionally, EarthJustice and Environmental Groups urge the Commission to encourage meaningful public participation in the regional transmission planning process, arguing that non-market participation is vital to achieving just, reasonable, and non-discriminatory system plans, and explaining that substantial financial assistance is necessary to assure such meaningful participation.

141. Some commenters, such as AWEA and Transmission Access Policy Study Group, support a requirement that there be an obligation to construct projects identified in regional transmission plans. AWEA recognizes that, while regional and interregional cost allocation arrangements may alleviate some of the impediments to building transmission facilities, an obligation to build projects identified in the regional transmission plan in non-RTO regions would help ensure that transmission facilities ultimately are constructed. In its reply comments, First Wind supports AWEA's comments. Transmission Access Policy Study Group suggests that the Commission can stimulate the construction of new projects, without expanding transmission providers'

obligation to build. It suggests requiring development of a process to obtain construction commitments, with accountability for those commitments. Transmission Access Policy Study Group states that the Final Rule should include a timely post-plan process for: (1) securing commitments by transmission providers (or others) to build the transmission facilities identified in the regional plan; and (2) holding transmission providers and others that commit to construct transmission facilities included in the regional base model accountable for doing so.

142. On the other hand, Edison Electric Institute argues that the identification of transmission facilities in a transmission plan does not impose an obligation to build them. In addition, Salt River Project asserts that a transmission plan is not a specific blueprint of projects that must be built and states that regional planning provides the valuable service of comparing and contrasting individual potential projects with the decision to build any given project coming after the transmission planning process, with only those projects deemed superior getting built. Salt River Project states that not all projects identified by the plan should be or will be developed. Large Public Power Council points to statements in the Proposed Rule providing that the Commission's intention is not to require construction, and that this decision not to compel construction is grounded in limitations on the Commission's statutory authority.

143. A number of commenters address the issue of whether merchant transmission developers, i.e., those transmission developers that are not seeking regional cost recovery

for proposed transmission projects, should be required to participate in the regional transmission planning process. Some commenters state that the Commission should clarify in the Final Rule that merchant transmission developers should not be required to participate in the regional transmission planning process.[134] Clean Line states that, if ratepayers are not bearing development risk and the developer is not seeking regional cost allocation for its project, then it should not be required to participate in the regional transmission planning process. Allegheny Energy Companies note that, in PJM's regional transmission planning process, such merchant transmission developers are not required to participate if they do not wish to do so. New York ISO states that it supports the proposal to not require transmission developers that do not seek to take advantage of a regional transmission cost allocation mechanism to participate in the regional transmission planning process. LS Power states that it understands that merchant transmission developers that did not participate in the regional transmission planning process would still be required to provide to public utility transmission providers the information that is needed, for example, for the reliable operation of the transmission grid.

144. However, others support requiring merchant transmission developers to participate

[134] *E.g.*, Allegheny Energy Companies; Champlain Hudson; Clean Line; H-P Energy Resources; LS Power; and New York ISO.

in the regional transmission planning process.[135] APPA states that the reasons for engaging in coordinated planning extend well beyond eligibility for inclusion in the regional transmission cost allocation mechanisms, noting that the development of transmission projects is a time-consuming and expensive endeavor. APPA argues that it is important for transmission planners to know about and fully analyze all of the various transmission alternatives to ascertain the impact of existing and proposed projects on other regional transmission facilities. Transmission Access Policy Study Group is concerned that exempting merchant transmission developers from the regional transmission planning process could cause the mandatory process to plan around *ad hoc* merchant transmission projects and would undermine the benefits of regional transmission planning, such as the development of a right-sized grid, and creates the potential for free ridership. In reply to Clean Line, Edison Electric Institute states that viable merchant transmission projects must be included in the regional transmission planning process, because such projects may have significant reliability, operational, and economic impacts on the transmission system.

[135] *E.g.*, APPA; Large Public Power Council; Massachusetts Municipal and New Hampshire Electric; MISO Transmission Owners; National Rural Electric Coops; Nebraska Public Power District; New England States Committee on Electricity; Northern Tier Transmission Group; Ohio Consumers Counsel and West Virginia Consumer Advocate Division; Old Dominion Electric Cooperative; Six Cities; Transmission Agency of Northern California; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

145. Finally, some commenters recommend that the Commission strongly encourage nonincumbent participation even in cases where they are not seeking regional cost recovery. California Commissions state that nonincumbent transmission developers that seek cost recovery via rolled-in rates should participate fully in the regional transmission planning process but believes that participation by merchant transmission developers that do not seek such cost recovery should be strongly encouraged to the extent feasible with regard to planning, but not to cost recovery. In its reply comments, Powerex notes that many commenters were opposed to exempting merchant transmission developers and thus recommended that the Commission encourage their participation in the regional transmission planning process.

### c. Commission Determination

146. This Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890 identified below. We determine that such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders. This will, in turn, help ensure that the rates, terms and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.

147. Order No. 890 required public utility transmission providers to coordinate at the

regional level for the purpose of sharing system plans and identifying system enhancements that could relieve congestion or integrate new resources.[136] The Commission did not specify, however, whether such coordination with regard to identifying system enhancements included an obligation for public utility transmission providers to take affirmative steps to identify potential solutions at the regional level that could better meet the needs of the region. As a result, the existing requirements of Order No. 890 permit regional transmission planning processes to be used as a forum merely to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. Consistent with the economic planning requirements of Order No. 890, regional transmission planning processes also must respond to requests by stakeholders to perform studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources or loads on an aggregated or regional basis.[137] Again, no affirmative obligation was placed on public utility transmission providers within a region to undertake such analyses in the absence of requests by stakeholders. There is also no obligation for public utility transmission providers within the region to develop a single transmission plan for the region that reflects their determination of the set of transmission facilities that more efficiently or cost-effectively

[136] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[137] *Id.*

meet the region's needs.

148. We address these deficiencies in the requirements of Order No. 890 through this Final Rule, beginning with the requirement that public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan. Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements, as discussed further below. When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of

cost allocation.[138]

149. We acknowledge that public utility transmission providers in some regions already meet or exceed this requirement.[139] As with other requirements in this Final Rule, our intent here is to establish a minimum set of obligations for public utility transmission providers that, as some commenters note, are not currently undertaking sufficient transmission planning activities at the regional level. We decline, however, to specify in this Final Rule a particular set of analyses that must be performed by public utility transmission providers within the regional transmission planning process. There are many ways potential upgrades to the transmission system can be studied in a regional transmission planning process, ranging from the use of scenario analyses to production cost or power flow simulations. We provide public utility transmission providers in each transmission planning region the flexibility to develop, in consultation with stakeholders, procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently

[138] As discussed in section IV.F.6, below, we conclude that the issue of cost recovery associated with non-transmission alternatives is beyond the scope of this Final Rule, which addresses the allocation of the costs of transmission facilities.

[139] As noted above, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission. Moreover, to the extent necessary, we clarify that nothing in this Final Rule is intended to modify or abrogate governance procedures of RTOs and ISOs.

or cost-effectively. We will review such mechanisms on compliance, using as our yardstick the statutory requirements of the FPA, Order No. 890 transmission planning principles, and our precedent regarding compliance with the Order No. 890 transmission planning principles, and issue further guidance as necessary.[140]

150. Because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, stakeholders must be provided with an opportunity to participate in that process in a timely and meaningful manner. Therefore, we apply the Order No. 890 transmission planning principles to the regional transmission planning process, as reformed by this Final Rule. This will ensure that stakeholders have an opportunity to express their needs, have access to information and an opportunity to provide information, and thus participate in the identification and evaluation of regional solutions. Ensuring access to the models and data used in the regional transmission planning process will allow stakeholders to determine if their needs are being addressed in a more efficient or cost-effective manner. Greater access to information and

[140] In developing their compliance filings, public utility transmission providers and interested parties should review the requirements as set forth in Order No. 890, Order No. 890-A, and our orders on compliance filings submitted by public utility transmission providers for guidance on what each of these transmission planning principles requires. For example, as a starting point, a public utility transmission provider should review the orders addressing its own compliance filings and the compliance filings for public utility transmission providers in its region. We do not address these principles in detail here, except with respect to the consideration of non-transmission alternatives in the regional transmission planning process and other discrete issues raised by commenters.

transparency also will help stakeholders to recognize and understand the benefits that they will receive from a transmission facility in a regional transmission plan. This consideration is particularly important in light of our reforms that require that each public utility transmission provider have a cost allocation method or methods for transmission facilities selected in a regional transmission plan that reflects the benefits that those transmission facilities provide.

151. Specifically, the requirements of this Final Rule build on the following transmission planning principles that we required in Order No. 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.[141] In Order No. 890, we required that each public utility transmission provider adopt these transmission planning principles as part of its individual transmission planning process. In this Final Rule, we expand the Order No. 890 requirements by directing public utility transmission providers to adopt these requirements with respect to the process used to produce a regional transmission plan. We conclude that it is appropriate to do so to ensure that regional transmission planning

[141] We do not include the regional participation transmission planning principle and the cost allocation transmission planning principle here because we address interregional transmission coordination and cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation elsewhere in this Final Rule.

processes are coordinated, open, and transparent.[142] Accordingly, we require public utility transmission providers to develop, in consultation with stakeholders,[143] enhancements to their regional transmission planning processes, consistent with these transmission planning principles.

152. We conclude that, without the requirement to meet the Order No. 890 transmission planning principles, a regional transmission planning process will not have the information needed to assess the impact of proposed transmission projects on the regional transmission grid. Additionally, absent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.

153. A number of commenters specifically address the treatment of non-transmission alternatives in the regional transmission planning process. Order No. 890's

[142] Although the explicit requirement for a public utility transmission provider to participate in a regional transmission planning process that complies with the Order No. 890 transmission planning principles identified above is new, we note that the existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these Final Rule requirements.

[143] The term "stakeholder" is intended to include any party interested in the regional transmission planning process. This is consistent with the approach taken in Order No. 890. *See, e.g., Southern Co. Svcs., Inc.*, 127 FERC ¶ 61,282, at P 14-16 (2009).

comparability transmission planning principle requires that the interests of public utility transmission providers and similarly situated customers be treated comparably in regional transmission planning.[144] In response to Order No. 890, public utility transmission providers have identified in their transmission planning processes where, when, and how transmission and non-transmission alternatives proposed by interested parties will be considered. As noted in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed.[145] As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with public utility transmission providers. With that said, the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.[146]

154. We disagree with those commenters that assert that non-transmission alternatives only should be considered in the local transmission planning process. We recognize that generation, demand response, and energy efficiency options often are considered in local resource planning and that transmission often is planned as a last resort. Therefore, when local transmission plans are brought together in a regional transmission planning process

[144] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494.

[145] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

[146] *Id*. P 454.

to determine if a regional solution can better meet the needs of the region than the sum of local transmission plans, many opportunities for the use of alternative resources will already have been considered. Just as there may be opportunities for regional transmission solutions to better meet the needs of the region, the same could be true for regional non-transmission alternatives. However, the regional transmission planning process is not the vehicle by which integrated resource planning is conducted; that may be a separate obligation imposed on many public utility transmission providers and under the purview of the states.

155. While we require the comparable consideration of transmission and non-transmission alternatives in the regional transmission planning process, we will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. Those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[147] However, we note that in Order Nos. 890 and 890-A, as well as in orders addressing related compliance filings, we have provided guidance regarding the requirements of the Order No. 890 comparability transmission planning

[147] We also deny, as beyond the scope of this proceeding, NRG's requests that we direct PJM to determine why its markets are not sending appropriate price signals and that we direct ISOs and RTOs to establish a "feedback loop."

principle.[148] Specifically, public utility transmission providers are required to identify how they will evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis.[149]

156. We disagree with concerns raised by certain commenters that the Order No. 890 comparability transmission planning principle may interfere with integrated resource planning.[150] As discussed above, this Final Rule in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over siting, permitting, or

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[148] *See, e.g.*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216. *See also, e.g., California Indep. Sys. Operator Corp.*, 123 FERC ¶ 61,283 (2008); *East Kentucky Power Coop*., 125 FERC ¶ 61,077 (2008).

[149] *See, e.g., NorthWestern Corp.*, 128 FERC ¶ 61,040 at P 38 (2009) (requiring the transmission provider's OATT to permit sponsors of transmission, generation, and demand resources to propose alternative solutions to identified needs and identify how the transmission provider will evaluate competing solutions when determining what facilities will be included in its transmission plan); *El Paso Elec. Co.*, 128 FERC ¶ 61,063 at P 15 (2009) (same); *New York Indep. Sys. Operator, Inc.*, 129 FERC ¶ 61,044, at P 35 (2009) (same). In each of these cases, the Commission stated that tariff language could, for example, state that solutions will be evaluated against each other based on a comparison of their relative economics and effectiveness of performance. Although the particular standard a public utility transmission provider uses to perform this evaluation can vary, the Commission explained that it should be clear from the tariff language how one type of investment would be considered against another and how the public utility transmission provider would choose one resource over another or a competing proposal. *Northwestern Corp.*, 128 FERC ¶ 61,040 at P 38, n.31; *El Paso Elec. Co.*, 128 FERC ¶ 61,063 at P 15, n.25; *New York Indep. Sys. Operator, Inc.*, 129 FERC ¶ 61,044 at P 35, n.26.

[150] *E.g.*, Ad Hoc Coalition of Southeastern Utilities.

construction of transmission solutions.[151] In addition, on compliance with Order No. 890, each public utility transmission provider already has put into place regional transmission planning processes that provide for the evaluation of proposed solutions on a comparable basis.[152] In this Final Rule, the Commission is applying to regional transmission planning the comparability transmission planning principle stated in Order Nos. 890 and 890-A.[153]

157. We agree with commenters that public utility transmission providers should have flexibility in determining the most appropriate manner to enhance existing regional transmission planning processes to comply with this Final Rule. As a result, and consistent with our approach in Order No. 890, we will not prescribe the exact manner in which public utility transmission providers must fulfill the requirements of complying with the regional transmission planning principles. We allow public utility transmission providers developing the regional transmission planning processes to craft, in consultation with stakeholders, requirements that work for their transmission planning region. Consistent with this approach, we will not impose additional rules that would

[151] *See supra* section III.A.2.

[152] *See, e.g.*, Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[153] *See, e.g.*, *supra* notes 148-49.

detail consistent planning cycles, impose stakeholder procedures, establish timelines for evaluating regional transmission projects in the regional transmission planning process (including establishing a minimum long-term planning horizons), add any additional requirements to the Order No. 890 dispute resolution transmission planning principle, or establish other planning criteria beyond those in this Final Rule, as requested by some commenters. These are matters best suited to resolution by the public utility transmission providers and stakeholders in the transmission planning region. We also reject Anbaric and PowerBridge's suggestion that procedures be developed to treat transmission project information as confidential, outside of the Commission's Critical Energy Infrastructure Information (CEII) requirements and regulations, as this runs counter to the requirement that regional transmission planning processes be open and transparent.

158. Additionally, we note that a public utility transmission provider's regional transmission planning process may utilize a "top down" approach, a "bottom up" approach, or some other approach so long as the public utility transmission provider complies with the requirements of this Final Rule. Public utility transmission providers have flexibility in developing the necessary enhancements to existing regional transmission planning processes to comply with this Final Rule, based upon the needs and characteristics of their transmission planning region.

159. We also decline to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan, as

requested by some commenters. The package of transmission planning and cost allocation reforms adopted in this Final Rule is designed to increase the likelihood that transmission facilities in regional transmission plans will move from the planning stage to construction. In addition, public utility transmission providers already are required to make available information regarding the status of transmission upgrades identified in transmission plans, including posting appropriate status information on its website, consistent with the Commission's CEII requirements and regulations.[154] To the extent an entity has undertaken a commitment to build a transmission facility in a regional transmission plan, that information should be included in such postings.[155] We determine that this obligation, together with the reforms we adopt in this Final Rule, are adequate without placing further obligations on public utility transmission providers.

160. The Commission also acknowledges the importance of identifying the appropriate size and scope of the regions over which regional transmission planning will be performed. We clarify that for purposes of this Final Rule, a transmission planning

[154] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

[155] Nothing in this Final Rule limits public utility transmission providers from developing mechanisms to impose an obligation to build transmission facilities in a regional transmission plan, consistent with the requirements below regarding the treatment of nonincumbent transmission developers. Similarly, nothing in this Final Rule preempts or otherwise limits any such obligation that may exist under state or local laws or regulations.

region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have agreed to participate in for purposes of regional transmission planning and development of a single regional transmission plan. As the Commission explained in Order No. 890, the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.[156] We note that every public utility transmission provider has already included itself in a region for purposes of complying with Order No. 890's regional participation transmission planning principle. We will not prescribe in this Final Rule the geographic scope of any transmission planning region. We believe that these existing regional processes should provide some guidance to public utility transmission providers in formulating transmission planning regions for purposes of complying with this Final Rule. However, to the extent necessary, we clarify that an individual public utility transmission provider cannot, by itself, satisfy the regional transmission planning requirements of either Order No. 890 or this Final Rule.

161. The Commission also clarifies that the obligation to participate in a regional transmission planning process that produces a regional transmission plan that meets the

[156] *See, e.g.*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527.

seven transmission planning principles, is not intended to appropriate, supplant, or impede any local transmission planning processes that public utility transmission providers undertake. The objective of this Final Rule is to amend the requirements of Order No. 890 so that regional transmission planning processes not only continue to meet the transmission planning principles established in Order No. 890 but, additionally, produce a regional transmission plan.

162. With regard to comments that seek clarification as to the applicability of the requirements of this Final Rule to transmission projects currently being proposed in existing regional transmission planning processes, we clarify in section II.D above that the requirements of this Final Rule are intended to apply to new transmission facilities. Our intent is to enhance transmission planning processes prospectively to provide greater openness and transparency in the development of regional transmission plans. As also discussed in section II.D above, we recognize that this Final Rule may be issued in the middle of a transmission planning cycle, and we therefore direct public utility transmission providers to explain in their respective compliance filings how they intend to implement the requirements of this Final Rule. In response to comments requesting that the Commission mandate that public utility transmission providers include a funding mechanism to facilitate the participation of in the regional transmission planning process of interested entities that are not market participants, this Final Rule affirms the general approach the Commission took in Order No. 890 regarding the recovery of costs

associated with participation in the transmission planning process. There, the Commission acknowledged concerns regarding "how state regulators and other agencies will recover the costs associated with their participation in the planning process."[157] The Commission therefore directed public utility transmission providers to "propose a mechanism for cost recovery in their planning compliance filings" and stated that those proposals "should include relevant cost recovery for state regulators, to the extent requested."[158] We decline to expand that directive here to include funding for other stakeholder interests, as requested by certain commenters. However, we also note that, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

163. With regard to the participation of merchant transmission developers in the regional transmission planning process, we conclude that, because a merchant transmission developer assumes all financial risk for developing its transmission project and constructing the proposed transmission facilities, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of

[157] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.339 and P 586.

[158] *Id.* n.339.

identifying the beneficiaries of its transmission project that would otherwise be the basis for securing eligibility to use a regional cost allocation method or methods.[159] However, we acknowledge the concern of some commenters that a transmission project proposed or developed by a merchant transmission developer has broader impacts than simply cost recovery. Because all electric systems within an integrated network are electrically connected, the addition or cancellation of a transmission project in one system can affect the nature of power flows within one system or on other systems.

164. We therefore conclude that it is necessary for a merchant transmission developer to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. We will allow public utility transmission providers in each transmission planning region, in consultation with stakeholders, in the first instance to propose what information would be required. Public utility transmission providers should include these requirements in their filings to comply with this Final Rule.

165. Although merchant transmission developers must provide information in the regional transmission planning process as discussed herein, to be clear, we emphasize that the transmission facilities proposed by a merchant transmission developer are not

[159] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 99.

subject to the evaluation and selection processes that apply to transmission facilities for which regional cost allocation is sought, as a merchant transmission developer is not seeking to be selected in the regional transmission plan for purposes of cost allocation. However, nothing in this Final Rule prevents a merchant transmission developer from voluntarily participating in the regional transmission planning process (beyond providing the information and data required above) even if it is not seeking regional cost allocation for its proposed transmission project. As we stated in the Proposed Rule, we encourage them to do so. In addition, nothing in this Final Rule limits or otherwise affects the responsibilities a merchant transmission developer may have to fund network upgrades caused by the interconnection of its project with the transmission grid.[160]

[160] We note that, to the extent a merchant transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it also will be required to comply with all applicable obligations, including registration with NERC. Under section 215, all users, owners, or operators of the bulk power system must register with NERC for performance of applicable reliability functions. The registration with NERC will help ensure that merchant transmission developers provide all appropriate information to be used in transmission system planning and assessment studies. *See* 16 U.S.C. 824o(g) ("Reliability Reports—The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America."); *see also Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, at P 803, *order on reh'g,* Order No. 672-A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006). Concerns regarding when NERC registration would be triggered should be addressed in a NERC registration process.

### 4. Consideration of Transmission Needs Driven by Public Policy Requirements[161]

#### a. Commission Proposal

166. The Proposed Rule would require that transmission needs driven by Public Policy Requirements be taken into account in the local and regional transmission planning process to ensure that each public utility transmission provider's transmission planning process supports rates, terms, and conditions of transmission service in interstate commerce that are just and reasonable and not unduly discriminatory or preferential. The Proposed Rule would require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.[162] The Commission noted that this proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the Order No. 890 economic planning studies transmission planning principle in the transmission planning process.[163] If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then the Proposed

[161] *See supra* P 2 (defining Public Policy Requirements).

[162] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64.

[163] *Id.*

Rule would require that the public utility transmission provider must make that demonstration in its compliance filing.[164]

167. The Proposed Rule would require each public utility transmission provider to coordinate with its stakeholders to identify Public Policy Requirements that are appropriate to include in its local and regional transmission planning processes.[165] The Proposed Rule stated that, after consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations.

168. The Proposed Rule sought comment on how planning criteria based on Public Policy Requirements should be formulated, including whether it would be more appropriate to use flexible criteria rather than "bright line" metrics when determining which transmission projects are to be included in a regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a transmission project is included in a regional transmission plan, and whether the use of "bright line" metrics may inappropriately result in alternating inclusion and exclusion of a single transmission project over successive planning cycles and thus create inappropriate

[164] *Id.* P 66.

[165] *Id.* P 65.

disruptions in long-term transmission planning.[166]

**b. Comments**

169. In general, most commenters support the Commission's proposal that each public utility transmission provider must amend its OATT such that local and regional transmission planning processes explicitly provide for the consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.[167] Support came from all sectors of the industry, including public utilities, municipal and cooperative utilities, renewable generators, transmission developers, state commissions, and consumer and public interest representatives. While most commenters support the proposal to include public policy requirements in

[166] *Id.* P 70.

[167] *E.g.*, Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission Agency of Northern California; Western Grid Group; and Wind Coalition.

transmission planning processes, a number seek clarification or request that the Commission provide additional guidance.

170. With regard to what constitutes a public policy requirement, some commenters seek to limit the definition to state and federal laws and regulations[168] while others seek a more flexible approach. For example, Omaha Public Power District supports the Commission's proposal only if such public policy requirements are established by state or federal laws or regulations applicable to all entities in the relevant planning region. East Texas Cooperatives believes that Omaha Public Power District's proposal strikes a reasonable balance. Similarly, National Rural Electric Coops state that the Commission should not empower stakeholders to use the transmission planning process to impose and enforce new resource planning requirements that lack the sanction of state or federal law in the planning region. First Energy Service Company argues that only enforceable requirements that are embodied in state or federal law should be eligible for inclusion in transmission planning processes. Duke states that the Final Rule should make unambiguous that the public policy aspect of regional and interregional planning refers only to those transmission projects driven by the need to comply with state and/or federal laws, rules, and/or regulations and that it supports limiting the requirement to public policies that drive the need for transmission.

[168] *E.g.*, Omaha Public Power District; Exelon; First Energy Services; PJM; New York ISO; and Transmission Agency of Northern California.

171. Likewise, PJM states that the Commission should make clear that the responsibility of the transmission planner to plan for public policy criteria is triggered by the clear and formal identification of those public policy criteria identified by Congress or state policymakers through publicly issued laws or regulations and recognize that the transmission planner would need to refer to the states to reconcile conflicting policies that cannot both be reasonably accommodated under a cost-effective and efficient regional transmission plan. In their reply comments, APPA, PSEG Companies, ISO/RTO Council, and Illinois Commerce Commission also caution about transmission planners picking and choosing the public policies that would be considered in transmission planning processes.

172. In their reply comments, ISO/RTO Council suggest that the Final Rule make clear that public policy objectives are limited to those developed by federal or state executive, legislative, and regulatory bodies with authority to adopt such objectives, that ISOs and RTOs may defer to regional state committees on identifying and reconciling individual state public policy goals, that states should utilize the authority under section 216(i) of the FPA to enter into regional compacts to ensure that recommendations pass constitutional muster and otherwise have a suitable legal foundation, and that stakeholders should advocate means of implementing state public policy mandates to the states rather than to ISOs/RTOs.

173. Several comments focus on the role of states in the identification of public policy

requirements and what constitutes such a requirement. Many request that the Final Rule expressly acknowledge the role of the state regulatory agencies and governors.[169] For example, PUC of Nevada supports the Commission's concept to require that public policies be incorporated into transmission planning and states that the Final Rule should specify the role state regulatory commissions and governors play in ensuring that the transmission plan accurately reflects state policies and, where there are inconsistencies in the utility's interpretation of the state's public policy versus that of the state regulatory commissions and governors, the Commission should give deference to the regulatory commissions' and governors' interpretation. PUC of Nevada also notes that the Final Rule does not include an oversight mechanism.

174. New England States Committee on Electricity conditions its support for the Commission's proposal on states identifying the policies established in law and regulations to be considered in transmission analysis. New York PSC comments that the Commission should modify the process to allow states to identify which state-level policies should be included in the transmission planning process. It also asks the Commission to clarify that these policies may include public policies derived pursuant to such statutory or regulatory authority, such as those created pursuant to regulatory orders or state energy plans and to allow states to identify state-level policies for inclusion in

[169] *E.g.*, Connecticut & Rhode Island Commissions; Massachusetts Departments; PUC of Nevada; and New England States Committee on Electricity.

those plans, not stakeholders. In reply comments, California PUC also states that the Commission should not establish prescriptive criteria regarding what policy goals are to be included. City of Los Angeles Department of Water and Power states that the Commission's proposal should be expanded to include local laws and regulations, noting that many requirements of entities such as itself are grounded in such local mandates.

175. NARUC notes that states will not turn over their policy authority to planning entities for inclusion in a Commission tariff and states that, while it is valuable to have transmission planning processes incorporate public policy considerations, a Commission tariff cannot mandate particular policy approaches. NARUC explains that transmission planners should not be required to determine unwritten public policy requirements, and that the Final Rule should explicitly recognize the governmental role, particularly at the state level, in providing policy input into the transmission planning processes, rather than directing the planners to consult with all stakeholders. NARUC states that the Final Rule should make explicit that any provisions do not impede or interfere with state commission authority to accept or approve integrated resource plans, make decisions about generation, demand-side resources, resource portfolios, or to modify policy based on cost thresholds. East Texas Cooperatives, First Wind, and Florida PSC express their support for NARUC's position.

176. Connecticut & Rhode Island Commissions state that the Commission should not prescribe any particular public policy requirement that must be considered or excluded

from the transmission planning process. Moreover, they argue that the states, not transmission utilities and planners, must retain their jurisdiction as the ultimate arbiter on the issue of whether a transmission project is the most beneficial, lowest cost, or most prudent decision for achieving a state public policy goal. North Carolina Agencies assert that the regional transmission planning processes should not decide how to meet state and federal policy requirements, and that the FPA gives the Commission no authority to determine what resources should be used by load-serving entities, regardless of whether or not those resources are needed to meet public policy requirements.

177. Others seek more flexibility in defining what constitutes a public policy requirement.[170] For example, Pacific Gas & Electric asks that the Final Rule clarify that local and regional transmission planning processes for public utility transmission providers consider state or federal public policy objectives rather than identifying or referring to specific laws and regulations. NextEra seeks clarification that any type of legal or regulatory requirements affecting transmission development should be included in the transmission planning process, noting that the EPA has established a schedule for issuing of a host of Clean Air Act rules governing other emissions from electric generating units. Iberdrola Renewables states that any state and federal renewable portfolio requirements and any state and federal greenhouse gas emission reduction or

[170] *E.g.*, New Jersey Division of Rate Counsel and Integrys.

climate change policies, including requirements or standards that take effect in future years, should be considered in the transmission expansion plan. Atlantic Wind Connection states that the Commission should broaden the phrase "public policy requirements" used in the Proposed Rule to include public policy initiatives or something similar to reflect the broad, non-compulsory nature of the policy environment.

178. Several commenters, including some consumer advocates and public interest organizations, recommend that the Commission specify the state and federal policy requirements that utilities, must, at a minimum, take into account in their transmission planning processes.[171] Some suggest including: (1) renewable portfolio standards; (2) energy efficiency standards and mandates; (3) $CO_2$ emissions reduction targets/requirements; (4) NAAQS attainment and interstate air pollution reductions; (5) EPA utility sector regulations; and (6) federal and state land management, land use, wildlife conservation and zoning policies and procedures intended to facilitate the siting of renewable energy.[172] In its reply comments, EarthJustice endorses this view. 26 Public Interest Organizations state that comparable consideration of all resource options

[171] *E.g.*, EarthJustice; 26 Public Interest Organizations; and National Audubon Society.

[172] *E.g.*, Conservation Law Foundation; Energy Future Coalition Group; E.ON Climate & Renewables North America; Environmental Defense Fund; Environmental NGOs; Natural Resources Defense Council; Sonoran Institute; and Wilderness Society and Western Resource Advocates.

available to meet various public policy requirements is essential to minimizing utilities' opportunities for undue discrimination. Ohio Consumers' Counsel and West Virginia Consumer Advocate Division state that transmission providers should be required describe the role that each "public policy" would play in the transmission planning process. Michigan Citizens Against Rate Excess state that while both reliability and public policy requirements should be considered as part of the same plan, they should be analyzed separately and the transmission plan should explain how these projects may complement or contradict each other.

179. Commenters that believe that the Commission should take a broader view of what public policy requirements are to be considered by transmission providers and their stakeholders, argue, for example, that the transmission planning process must be sufficiently flexible to include reasonably foreseeable public policy objectives not yet explicitly required by existing law or regulation and also to consider "at risk" generation.[173] Atlantic Wind Connection suggests the adoption of an unambiguous requirement to plan transmission additions needed to accommodate public policy initiatives and suggests that the Commission require specific tariff provisions describing how transmission facilities that accommodate and facilitate public policy initiatives would be planned for and evaluated. AWEA states that the Commission should clarify

[173] *E.g.*, Iberdrola Renewables.

that public policy requirements are not to be narrowly construed and that expected future public policy requirements as well as existing ones should be considered.

180. However, in reply, a number of commenters take exception with the suggestion that possible or likely future public policies should be considered in the transmission planning process stating, among other things, that it could result in constantly moving targets, unfocused transmission planning, regulatory uncertainty, and the RTOs or the Commission assuming the roles of Congress and the states.[174] For example, Exelon argues that the Final Rule should specify that planning for public policy should not include aspirational goals. Likewise, Large Public Power Council's reply comments state that transmission planners should not be required to take into account anticipated public policies. Xcel also believes that the requirement to consider public policy directives in developing transmission plans should focus on established policies, rather than anticipated or potential future obligations.

181. Among those seeking flexibility and recognition of regional differences,[175] Edison Electric Institute and Northeast Utilities state that the Commission should allow flexibility in defining the types of public policy requirements; determining

[174] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Coalition for Fair Transmission Policy; East Texas Cooperatives; Large Public Power Council; National Rural Electric Coops; and New England States Committee on Electricity.

[175] *E.g.*, ISO/RTO Council; ISO New England; PJM; New York ISO; SPP; MISO; New York Transmission Owners; NEPOOL; and MISO Transmission Owners.

implementation details, such as the process to identify public policy requirements; and how transmission system needs would be selected once an appropriate public policy requirement is identified. Northern Tier Transmission Group states that to the extent that a transmission provider maintains an obligation to serve retail load, its merchant/load-serving function will identify and quantify the relevant public policy requirements, which will then be accounted for in its local transmission plan. Any additional public policy objectives should be at the discretion of regional planning groups. Transmission Access Policy Study Group states that the Final Rule should clarify the reference to state and federal policy requirements, so that it includes state regulatory commission orders and regulations and local governmental mandates on load-serving entities; and expressly identify FPA section 217(b)(4) as a federal public policy requirement that the regional transmission planning process must consider.

182. Other commenters have ideas on or questions about how public policy requirements are to be included and implemented. Exelon states that the Commission should adopt principles to help head off stalemates: (1) transmission planning must include likely retirements of plants subject to environmental regulations; (2) encompass only laws actually in effect in determining the impact on generation capacity; (3) require transmission planners to take into account all the actual terms of state and federal laws and regulations for which transmission expansion is planned; (4) require a region to show that its stakeholder-endorsed policy would not cause any harm or costs to other regions;

(5) the full cost of resources must be transparent and considered in the transmission planning process, based on sound economic principles; and (6) require that planning for renewable energy resources be done with the objective of minimizing total costs. MISO states that the proposal should be expanded to include a requirement to, when prudent, pursue appropriate transmission expansion initiatives to facilitate the compliance of public policy requirements by entities within the transmission provider's footprint that are subject to such requirements.

183. PJM states that the actual development of transmission to address public policy standards requires: (1) further direction as to how such standards should be reflected in implementable planning assumptions; and (2) a legally empowered coordination among states with shared policy agendas allowing regional projects to be sited and permitted because they are "needed" to meet the multistate collective's shared policy agenda. Old Dominion and Atlantic Wind Connection support PJM's suggested holistic approach to transmission planning. In response, however, Consolidated Edison and Orange & Rockland argue that PJM's comments do not adequately reflect the Proposed Rule's objective to respect regional methods and urge the Commission to reject PJM's top down approach.

184. Pattern Transmission states that the Commission should require public utility transmission providers to specify when transmission upgrade projects are categorized as public policy-driven projects and when the transmission facilities are considered solely

through the generator interconnection process.

185. Others offer for Commission consideration their desired outcomes from including Public Policy Requirements in regional transmission planning.[176] For example, Transmission Agency of Northern California seeks confirmation that simply characterizing a project's purpose as meeting a public policy requirement should not provide that project a presumption of inclusion in the regional transmission planning process. Transmission Access Policy Study Group states that the Commission should urge transmission providers to adopt a "no regrets" strategy that focuses on constructing transmission facilities needed under multiple potential power supply and public policy scenarios, which lead to a "right-sized" grid with greater flexibility to respond to changing technology, resource options, and customer needs. Old Dominion also asks that the Final Rule make clear that the directive to plan for public policy laws or regulations is for transmission planning only, not for design and construction or to improve power supply.

186. Western Grid Group states that, at a minimum, the Commission should require regional plans to address a planning horizon of at least 20 years and to evaluate environmental and economic constraints and public interest concerns over that horizon as a basis for the development of such plans. Powerex cautions that the consideration of

[176] *E.g.*, Pattern Transmission; Transmission Agency of Northern California; and Transmission Access Policy Study Group.

public policy factors not result in transmission planning and cost allocation processes that elevate the needs of certain customers over others in the transmission planning process and should preserve competitive wholesale power markets.

187. Commenters also offer ideas on timing and scope. Some commenters argue that only federal and state laws and regulations in effect during the transmission planning cycle should be considered as public policy requirements in the regional transmission planning process.[177] East Texas Cooperatives, however, believes that a better approach is to let participants in the transmission planning process advocate for their own needs and interests (which by necessity will reflect the need to comply with policies contained in applicable federal and state law), and then allow the transmission planning process to sort out these interests within the existing Order No. 890 transmission planning framework. In response to such comments, however, AEP contends that planning for only current regulatory requirements is too narrow a formulation that would result in underinvestment in transmission infrastructure. AEP suggests that the transmission planning process consider reasonably foreseeable future regulatory requirements given their likely impact on the power system, citing NERC's analysis of potential impacts of EPA regulations on generation.

[177] *E.g.*, National Rural Electric Coops; City of Santa Clara; Michigan Citizens Against Rate Excess; Exelon; East Texas Cooperatives; and Coalition for Fair Transmission Policy.

188. A number of commenters believe either that existing regional transmission planning processes already consider public policy requirements and thus OATT revisions may therefore be unnecessary.[178] East Texas Cooperatives state that they agree with the Commission's preliminary finding, but disagree as to the need for any revisions to the OATT as transmission planning already takes into account public policy requirements established by state or federal laws or regulations in accordance with Order No. 890's transmission planning requirements, as well as with Commission policy that has evolved over the years. Many commenters in ISO and RTO regions argue that the transmission planning processes administered by those entities already address or largely address public policy issues.[179] For example, New York ISO supports the Commission's proposal but states that existing transmission planning rules already provide for consideration of public policy requirements in many regions. Transmission Dependent Utility Systems recommend that the Commission clarify that nothing in the existing *pro forma* OATT prohibits the consideration of public policy requirements in the transmission planning processes and, to the extent a transmission provider believes its particular OATT does preclude such considerations, the Final Rule should direct

[178] *E.g.*, Washington Utilities and Transportation Commission; Alliant Energy; Xcel; Bonneville Power; Westar; Sacramento Municipal Utility District; National Rural Electric Coops; East Texas Cooperatives; WECC; WestConnect; Georgia Transmission Corporation; Southern Companies; and Ad Hoc Coalition of Southeastern Utilities.

[179] *E.g.*, New England Transmission Owners; Alliant Energy; and New York ISO.

compliance filings to remove the language allegedly prohibiting such consideration.

189. Some commenters raise additional concerns, including how public policy considerations would be incorporated into a transmission provider's local and regional transmission planning process including whether the proposal is intended to modify or incorporate generator interconnection requests into the "local and regional transmission planning process;" whether a project proposed to satisfy transmission needs driven by public policy requirements are to be planned for and considered separately from reliability and economic projects; whether regional transmission planning organizations are required to create a separate category of public policy-driven transmission projects or whether they are to be in concert with reliability and economic criteria during the transmission planning process.[180]

190. Coalition for Fair Transmission Policy is concerned that the Proposed Rule might be interpreted as requiring transmission planning processes to make decisions as to how best to meet applicable public policy requirements on behalf of those entities on whom the requirements are placed. Therefore, it states that decisions on how load-serving entities within regions should meet state or federal public policy requirements should continue to be made by those with responsibilities to meet the requirements, based on federal and state law and applicable regulations, and recommends that the Final Rule

[180] *E.g.*, NV Energy; Long Island Power Authority; and Bonneville Power.

make this clear.

191. PPL Companies state that basing transmission planning decisions on state public policy directives may lead to undue discrimination among generators and, thus, run afoul of the FPA requirement that all users of the transmission system be treated in a non-discriminatory manner. It states that the Commission should direct transmission planners to make sure that pre-existing rights are preserved and accommodated under the Proposed Rule's transmission planning principles, just as the Commission preserved grandfathered transmission contracts under Order No. 888 and grandfathered interconnection agreements under Order No. 2000.

192. New Jersey Board believes there needs to be recognition of planning for public policy goals in terms of reliability. It asserts that focusing solely on public policy goals as the driving force in the transmission planning process would raise issues as to which policy should receive the greatest emphasis, and would cause conflict in the transmission planning process over which goals to incorporate. New Jersey Board recommends that transmission plans incorporate public policy goals in a fashion that has these projects evaluated similarly for reliability and economic purposes.

193. Some commenters generally oppose the proposal to require public policy considerations in transmission planning.[181] PSEG Companies state that the

[181] *E.g.*, PSEG Companies; First Energy Service Company; Ad Hoc Coalition of

(continued…)

Commission's public policy planning approach should not be adopted, arguing that the proposal would result in public utility transmission providers establishing an unduly preferential practice favoring renewable energy resources over other types of resources. Finally, PSEG Companies are concerned that the proposal could result in overbuilding or underbuilding the transmission grid. Ad Hoc Coalition of Southeastern Utilities asserts that there is no dependable means to translate abstract notions of public policy into the transmission planning process, except to the extent it has a bearing on transmission demand. Energy Consulting Group states that interregional planning should not be used as an instrument of public policy but should incent development of transmission improvements to afford the public access to all types of generation that is economic and minimizes its power costs. APPA believes that any transmission provider wishing to incorporate specific state policy requirements or other objectives into its transmission planning protocols should do so through case-by-case tariff filings under FPA section 205.

194. Electricity Consumers Resource Council and the Associated Industrial Groups are concerned with mandatory interjection of state public policy considerations into the transmission planning process and how, in practice, this is expected to work, given public policy differences among states, and they are concerned that the Proposed Rule delegates

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Southeastern Utilities; National Rural Electric Coops; Southern Companies; Large Public Power Council; Nebraska Public Power District; and Long Island Power Authority.

to ISOs and RTOs the authority to impose the public policy requirements of one state on another without sufficient democratic or procedural checks and balances.

195. Some commenters agree with the proposal to coordinate identification of public policy requirements. These commenters generally state that flexibility is needed given the regional variation in: public policy objectives; types and location of resources; and regional needs, provided that transmission providers seek input from state authorities and other stakeholders.[182] MISO Transmission Owners ask that the Commission not mandate what public policy requirements must be considered, but should allow individual transmission providers to work with stakeholders to identify public policy requirements applicable to the state(s) or region in which the transmission provider is located; they also state that transmission planning regions should not be required to plan for or contribute to the costs of enabling compliance with public policy requirements enacted outside of their region without the agreement of all regions affected.

196. Some commenters agree that public utility transmission providers should be required to specify the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements. 26 Public Interest Organizations assert that the Commission should require all transmission providers to incorporate certain best

[182] *E.g.*, American Transmission; Atlantic Grid; Consolidated Edison and Orange & Rockland; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; NEPOOL; New England Transmission Owners; New York Transmission Owners; and Northeast Utilities.

practices in the OATT to achieve the Commission's goal. These include: (1) minimum coordination agreement requirements for plan development; (2) required actions to assure robust participation in regional plan development by non-market participant stakeholders; and (3) minimum requirements to ensure fair and comparable consideration of all options to meet public policy requirements. Clean Energy Group states that transmission planners should be required to identify the specific public policy goals that would be considered in the planning cycle after consultation with stakeholders, including state policy makers. Additionally, it states that transmission providers should be required to disclose and document how public policy considerations were taken into account.

197. Other commenters would like flexibility in this regard. Edison Electric Institute states that the Commission should not require transmission providers to identify in their tariff each specific public policy requirement that may be taken into consideration but should allow flexibility. ISO New England and Kansas City Power & Light and KCP&L Greater Missouri similarly argue that the Commission should specify that it would not become a requirement within the tariff to list each specific public policy requirement. However, in reply, Conservation Law Foundation argues that the policies should be reflected in the OATT and asks that the Final Rule hold planning authorities responsible for applying those policies that are germane to a given process or decision. In their reply comments, Maine Parties point to MISO tariff provisions that show that ISOs and RTOs can develop tariff provisions that include criteria for identifying public policy projects,

and request that the Commission be explicit about the role it expects ISOs and RTOs to play in identifying state and federal public policies and in identifying criteria for selecting projects.

198. In response to the Commission's question regarding the use of "bright line" metrics when evaluating potential transmission projects, the majority of commenters that provided input on this issue support a flexible approach.[183] They generally agree that transmission providers should be provided flexibility to take into account the multiple reliability, economic, and public policy-based benefits a single project may provide. They express concern that projects that address reliability, economic, and public policy initiatives may not be pursued because the transmission provider may not be allowed to include the project in the regional plan because of the technical failure to meet a bright line test. AWEA notes that existing transmission planning processes that rely on bright line criteria do not accommodate well the integration of renewable resources into the grid. NRECA states that bright line metrics are unnecessary because load-serving entities' planning requirements implicitly include established public policy requirements.

199. While expressing the need for flexibility, some commenters note that the Commission should establish in the Final Rule some level of specificity as to how the

[183] *E.g.*, Anbaric and PowerBridge; Atlantic Grid; AWEA; First Wind; Integrys; National Rural Electric Coops; New Jersey Division of Rate Counsel; New York ISO; New York Transmission Owners; NextEra; Northeast Utilities; Northern Tier Transmission Group; Organization of MISO States; PJM; SPP; WECC; and Westar.

regional plan should consider projects designed to meet public policy requirements. NEPOOL suggests that the Commission grant deference to the states in a planning region with regard to how they would want public policy requirements to be considered in the context of regional planning. SPP echoes this, stating that the Commission should afford transmission providers, state regulatory commissions, and stakeholders flexibility to develop strategies and metrics that appropriately consider the needs and reflect the existing structure of the transmission system in the region. First Wind recognizes that certain public policy considerations could require a bright line metric to ensure they be included in a regional plan, while others could be more general and flexible.

200. Others, however, argue that bright line metrics are necessary to avoid discrimination in the transmission planning process.[184] City and County of San Francisco and LS Power both assert that removing bright line criteria would lead to unfair results. City and County of San Francisco assert that without bright line criteria, end-users could be penalized because of different cost allocation methods associated with each distinct

[184] *E.g.*, City and County of San Francisco; LS Power; New Jersey Division of Rate Counsel; and Western Independent Transmission Group.

criterion.

201. Some commenters support a balanced approach of using both bright line and flexible metrics. While Organization of MISO States cautions against the establishment of rigid bright line metrics, it notes that an overly flexible approach could allow for higher cost projects than are actually needed. It states that the Commission should seek a reasonable balance by ordering transmission planners to start with defined criteria and then look further into more flexible options that could provide an optimal solution to a number of perceived needs. Dominion states that both flexible and bright line criteria may be needed for some multi-purpose projects. Dominion explains that the benefit of reliability projects must be assessed against bright line criteria. However, when considering other benefits, Dominion states that more flexibility is needed. Minnesota PUC and Minnesota Office of Energy Security recommend that bright line metrics be

used as a first pass in the transmission planning process, but more flexible criteria could be used to assess each project further.

202. Finally, there are some commenters that argue that the Commission's proposal may lead to undesirable outcomes. Large Public Power Council states that requiring each public utility transmission provider to coordinate with customers and other stakeholders to identify relevant state and federal laws and regulations would be unnecessary, potentially confusing, and ultimately counterproductive. Long Island Power Authority

states that the Proposed Rule did not identify how a regional transmission planning group encompassing multiple states is to decide which state's "public policy requirements" must be satisfied through the transmission planning process. It expresses concern that the apparent default solution of incorporating every state's public policy requirements into the transmission planning process to the extent feasible, may distort the transmission planning process, lead to over-construction of transmission facilities and consequently increase the costs to be allocated. Nebraska Public Power District states that the discretion that this approach would interject into the transmission planning process would seem to be an open door to potential discrimination, and a nightmare to enforce, as parties debate whether planning adequately responds to a variety of potentially competing policies.

### c. Commission Determination

203. The Commission requires public utility transmission providers to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[185] As discussed in section II above, the reforms adopted below are intended to ensure that the local and regional transmission planning processes support the

[185] To the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some ISO/RTO regions, the requirements of this Final Rule with regard to Public Policy Requirements apply only to the regional transmission planning process.

development of more efficient or cost-effective transmission facilities to meet the transmission needs driven by Public Policy Requirements, which will help ensure that the rates, terms and conditions of jurisdictional service are just and reasonable. Moreover, these reforms will remedy opportunities for undue discrimination by requiring public utility transmission providers to have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by Public Policy Requirements, rather than the public utility transmission provider planning only for its own needs or the needs of its native load customers. Our decision here to require transmission planning to include the consideration of transmission needs driven by Public Policy Requirements is supported by the numerous commenters who generally agree with the proposed reforms.[186]

[186] *E.g.*, Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission

(continued…)

204. Under the existing requirements of Order No. 890, there is no affirmative obligation placed on public utility transmission providers to consider in the transmission planning process the effect that Public Policy Requirements may have on local and regional transmission needs.[187] We agree with the concerns of many commenters that, without having in place procedures to consider transmission needs driven by Public Policy Requirements, the needs of wholesale customers may not be accurately identified.[188] While we understand that some public utility transmission providers already do have processes in place to determine whether transmission needs reflect Public Policy Requirements, others do not. We correct this deficiency through the requirements below, which are intended to enhance, rather than replace, existing transmission planning obligations under Order No. 890. Moreover, as with other reforms adopted in this Final Rule, these requirements are intended to be an additional set of minimum obligations for public utility transmission providers and are not intended to preclude additional transmission planning related activities.

205. In response to commenters seeking greater clarity as to how transmission needs

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Agency of Northern California; Western Grid Group; and Wind Coalition.

[187] In response to Transmission Dependent Utility Systems, we note that nothing in the existing *pro forma* OATT affirmatively prohibits consideration of the effect of Public Policy Requirements on transmission needs.

[188] *E.g.*, National Grid; NextEra; AWEA; Atlantic Grid; Delaware PSC; Anbaric and PowerBridge; and Conservation Law Foundation.

driven by Public Policy Requirements must be considered by public utility transmission providers, we clarify that by considering transmission needs driven by Public Policy Requirements, we mean: (1) the identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those needs. We therefore direct public utility transmission providers to amend their OATTs to describe the procedures by which transmission needs driven by Public Policy Requirements will be identified in the local and regional transmission planning processes and how potential solutions to the identified transmission needs will be evaluated in the local and regional transmission planning processes. We discuss each of these requirements in turn.

206. First, public utility transmission providers must establish, in consultation with stakeholders, procedures under which public utility transmission providers and stakeholders will identify those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated. Various commenters express concern that a public utility transmission provider should not have an open-ended obligation to undertake costly and time-consuming studies to evaluate the potential impact that every Public Policy Requirement might have on transmission development. As noted by Connecticut & Rhode Island Commissions, for example, entities subject to particular requirements may intend to meet them in ways that do not involve the planning of transmission within the local or regional transmission planning processes. In other

circumstances, there may be disagreement among the various entities subject to competing Public Policy Requirements as to whether it is appropriate to consider the impact of complying with those laws and regulations in the transmission planning process.

207. We do not in this Final Rule require the identification of any particular transmission need driven by any particular Public Policy Requirements. Instead, we require each public utility transmission provider to establish procedures for identifying those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated in the local or regional transmission planning processes. As part of the process for identifying transmission needs driven by Public Policy Requirements, such procedures must allow stakeholders an opportunity to provide input, and offer proposals regarding the transmission needs they believe are driven by Public Policy Requirements. To the extent such procedures identify no transmission needs driven by a Public Policy Requirement, the relevant public utility transmission providers are under no obligation to evaluate potential transmission solutions.

208. We allow for local and regional flexibility in designing the procedures for identifying the transmission needs driven by Public Policy Requirements for which potential solutions will be evaluated in the local or regional transmission planning processes. The effects of Public Policy Requirements on transmission needs are highly variable based on geography, existing resources, and transmission constraints. We

therefore conclude that it is appropriate to require public utility transmission providers, in consultation with their stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by Public Policy Requirements in their area, subject to our review on compliance. At a minimum, however, we require that all such procedures allow for input from stakeholders, including but not limited to those responsible for complying with the Public Policy Requirement(s) at issue and developers of potential transmission facilities that are needed to comply with one or more Public Policy Requirements.

209. We decline to require that transmission needs driven by Public Policy Requirements be identified by a particular entity or subset of stakeholders. However, all stakeholders must have an opportunity to provide input and offer proposals regarding the transmission needs they believe should be so identified, as discussed above. In other words, while the procedures adopted by public utility transmission providers in response to this Final Rule must allow all stakeholders to bring forth any transmission needs they believe are driven by Public Policy Requirements, those procedures must also establish a just and reasonable and not unduly discriminatory process through which public utility transmission providers will identify, out of this larger set of needs, those needs for which transmission solutions will be evaluated. Some public utility transmission providers might conclude, in consultation with stakeholders, to develop procedures that rely on a committee of load-serving entities, a committee of state regulators, or a stakeholder group

to identify those transmission needs for which potential solutions will be evaluated in the transmission planning processes.[189] Another example would be the case where a public utility transmission provider identifies such transmission needs itself on behalf of its customers, following consultation with stakeholders, including participating state regulators. However, to ensure that requests to include transmission needs are reviewed in a fair and non-discriminatory manner, we require public utility transmission providers to post on their websites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated. We conclude that this posting requirement is necessary to provide the Commission and interested parties with information as to how the identification procedures are implemented by public utility transmission providers.

210. We decline in this Final Rule to require the identification of any particular set of transmission needs driven by any particular Public Policy Requirements in the local and regional transmission planning processes of public utility transmission providers. To the extent that implementation of the procedures required here results in a suggested

[189] As noted below, we strongly encourage states to participate actively in the identification of transmission needs driven by Public Policy Requirements. Public utility transmission providers, for example, could rely on committees of state regulators or, with appropriate approval from Congress, compacts between interested states to identify transmission needs driven by Public Policy Requirements for the public utility transmission providers to evaluate in the transmission planning process.

transmission need not being evaluated for potential solutions in the local or regional transmission planning process, the relevant public utility transmission provider(s) are under no obligation under this Final Rule to evaluate the potential effect of the associated Public Policy Requirement on transmission development. This includes proposals to evaluate the need for particular transmission facilities proposed by transmission developers to comply with Public Policy Requirements. While these entities may continue to offer their proposed transmission facilities in the local or regional transmission planning process as a potential solution to transmission needs, such proposals would not be evaluated in the transmission planning process as driven by a Public Policy Requirement.

211. With regard to the evaluation of potential solutions to the identified transmission needs driven by Public Policy Requirements, we again leave to public utility transmission providers to determine, in consultation with stakeholders, the procedures for how such evaluations will be undertaken, subject to the Commission's review on compliance and with the objective of meeting the identified transmission needs more efficiently and cost-effectively. [190] As noted in our discussion of regional transmission planning in section

[190] To the extent a public utility transmission provider determines that existing provisions of its OATT must be amended in order to implement its evaluation process, it may include such tariff revisions in its compliance filing. For example, evaluation of transmission needs driven by a particular Public Policy Requirement could require the gathering of additional information from interconnected generators regarding retirements

(continued…)

III.A above, there are many ways potential upgrades to the transmission system can be evaluated, ranging from the use of scenario analyses to production cost or power flow simulations. At a minimum, however, this process must include the evaluation of proposals by stakeholders for transmission facilities proposed to satisfy an identified transmission need driven by Public Policy Requirements.[191] However, as with any proposed solution offered in the local or regional transmission planning processes for transmission needs driven by reliability issues or economic considerations, there is no assurance that any proposed transmission facility will be found to be an efficient or cost-effective solution to meet local or regional needs.

212. In response to commenters that urge us to recognize the role of the states in transmission planning, especially as it relates to compliance with Public Policy Requirements, we clarify that nothing in this Final Rule is intended to alter the role of states in that regard. Through this Final Rule, we are requiring public utility transmission providers to provide an opportunity to all stakeholders, including state regulatory authorities, to provide input on those transmission needs they believe are driven by Public Policy Requirements, to the extent they are not already doing so. We are not dictating

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or from network customers regarding resource preferences.

[191] This requirement is consistent with the existing requirements of Order Nos. 890 and 890-A which permit sponsors of transmission and non-transmission solutions to propose alternatives to identified needs. *See supra* note 149.

any substantive result with regard to compliance with Public Policy Requirements. In Order No. 890, the Commission stated its expectation that "all transmission providers will respect states' concerns" when engaging in the regional transmission planning process.[192] This is equally true with regard to the consideration of transmission needs driven by Public Policy Requirements. We strongly encourage states to participate actively in both the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs.

213. We therefore do not believe our reforms are inconsistent with state authority with respect to integrated resource planning, as suggested by some commenters. Indeed, we believe that the requirements imposed herein complement state efforts by helping to ensure that potential solutions to identified transmission needs driven by Public Policy Requirements of the states can be evaluated in local and regional transmission planning processes. To be clear, however, while a public utility transmission provider is required under this Final Rule to evaluate in its local and regional transmission planning processes those identified transmission needs driven by Public Policy Requirements, that obligation does not establish an independent requirement to satisfy such Public Policy Requirements. In other words, the requirements established herein do not convert a failure of a public utility transmission provider to comply with a Public Policy

[192] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

Requirement established under state law into a violation of its OATT.

214. We do not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations or to specify additional public policy principles or public policy objectives as some commenters have suggested. Based on the record before us, we believe it is sufficient to ensure just and reasonable rates and to avoid the potential for undue discrimination to restrict the requirement for public policy consideration to state or federal laws or regulations that drive transmission needs. Likewise, we will not require restrictions on the type or number of Public Policy Requirements to be considered as long as any such requirements arise from state or federal laws or regulations that drive transmission needs and as long as the requirements of the procedures required herein are met.

215. Some commenters request that we specify EPA regulations or FPA section 217 as Public Policy Requirements driving potential transmission needs relevant for consideration in the transmission planning process. While we decline to mandate the consideration of transmission needs driven by any particular Public Policy Requirement, we intend that the procedures required above be flexible enough to allow for stakeholders to suggest consideration of transmissions needs driven by any Public Policy Requirement, including potential consideration of requirements under EPA regulations, FPA section 217, or any other federal or state law or regulation that drive transmission needs.

Because we are not mandating the consideration of any particular transmission need driven by a Public Policy Requirement, we disagree with PSEG Companies that we are favoring renewable energy resources over other types of resources.

216. We reiterate here and clarify a statement of the Proposed Rule that generated significant comment; that is, this Final Rule does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by state or federal laws or regulations.[193] By providing this clarification, we are neither affirmatively granting new rights to nor imposing an obligation on a public utility transmission provider. Instead, the statement is a recognition that a public utility transmission provider has, and has always had, the ability to plan for any transmission system needs that it foresees. Our recognition of this ability is not intended to limit or expand in any way the option that a public utility transmission provider has always had to plan for facilities that it believes are needed if it chooses to do so. We believe that public utility transmission providers, in consultation with stakeholders, are in the best position to determine whether to consider in a transmission planning process any public policy

[193] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64. For example, a public utility transmission provider and its stakeholders are not precluded under this Final Rule from choosing to plan for state public policy goals that have not yet been codified into state law, which they nonetheless consider to be important long-term planning considerations.

objectives beyond those required by this Final Rule. We reiterate that this Final Rule creates no obligation for any public utility transmission provider or its transmission planning processes to consider transmission needs driven by a public policy objective that is not specifically required by state or federal laws or regulations. If public utility transmission providers, in consultation with stakeholders, do identify public policy objectives not specifically required by state or federal laws or regulations, we note that transmission facilities designed to meet these objectives may be eligible for cost allocation under the transmission planning process.

217. We note that identifying a set of transmission needs and projects for inclusion in a transmission planning study does not ensure that any particular transmission project will be in the regional transmission plan. Alternative solutions to the identified needs may prove better from cost, siting, or other perspectives. Similarly, elimination of a transmission project or need from the transmission planning process would not prevent any planner or developer from independently seeking to satisfy the need or develop the transmission project, but any resulting transmission facility would not be eligible for cost allocation under a regional cost allocation method or methods required under this Final Rule.

218. Some commenters have expressed concerns that the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process will result in costs being assigned to regions that do not benefit from those requirements or to

regions that did not create the need for new transmission. We understand these commenters to be concerned that a requirement to consider transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes will result in cross-subsidization of the costs of meeting Public Policy Requirements.

219. We clarify that any such consideration of transmission needs driven by Public Policy Requirements, to the extent that it results in new transmission costs, must follow the cost allocation principles discussed separately herein.[194] Particularly, the costs of new transmission facilities allocated within the planning region must be allocated within the region in a manner that is at least roughly commensurate with estimated benefits. [195] Those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities. That is, a utility or other entity that receives no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities.

220. Further, we are not requiring that a separate class of transmission projects be created in the transmission planning process related to compliance with Public Policy

[194] *See* discussion *infra* section IV.

[195] *See* discussion *infra* section IV.E.2.

Requirements, although nothing in this Final Rule prohibits the development of a separate class of transmission projects if the public utility transmission provider and its stakeholders believe that it is appropriate to do so. Some public utility transmission providers might comply with this Final Rule by implementing procedures to consider transmission needs driven by Public Policy Requirements separately from transmission addressing reliability needs or economic considerations. Other public utility transmission providers might comply with this Final Rule by identifying and evaluating all transmission needs, whether driven by Public Policy Requirements, compliance with reliability criteria, or economic considerations. While we provide flexibility for public utility transmission providers to develop procedures appropriate for their local and regional transmission planning processes, we reiterate that all stakeholders must be provided an opportunity to provide input during the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs, as discussed above.

221. In response to Northern Tier Transmission Group, we understand that a public utility transmission provider with a native load obligation may already have addressed compliance with Public Policy Requirements in developing its resource assumptions to be used in the transmission planning process. In such circumstances, the procedures used to identify transmission needs driven by Public Policy Requirements should take that into account. Similarly, the evaluation of potential solutions to those transmission needs

identified in a local or regional transmission planning process should reflect the resource decisions of the transmission planning process.

222. The Proposed Rule stated that, if a public utility transmission provider believes that its existing transmission planning process already meets the requirements to consider Public Policy Requirements, then it may make that demonstration in compliance with the Final Rule.[196] Certain commenters question the need for these requirements altogether because they assert they are already obligated to follow all state or federal laws or regulations, including laws or regulations related to public policy objectives. Other commenters, particularly those in ISO and RTO regions, assert that the transmission planning processes administered by those entities already address public policy issues so their compliance obligation should be minimal. In this Final Rule, the Commission is expanding the requirements of the *pro forma* OATT to require that transmission planning processes affirmatively consider transmission needs driven by Public Policy Requirements. Each public utility transmission provider will have the opportunity to demonstrate compliance with these requirements by specifying the procedures in its local and regional transmission planning processes, whether existing or new, for identifying transmission needs driven by Public Policy Requirements and for evaluating potential solutions to meet those identified needs. As with other requirements of this Final Rule,

[196] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 66.

we decline here to prejudge any compliance filings or predetermine whether any public utility transmission provider may already be in compliance.

223. Finally, we considered the many comments on whether it is more appropriate to use flexible criteria in lieu of "bright line" metrics when determining which transmission projects are in the regional transmission plan. While we have in the past required adoption of a formulaic approach to applying such metrics,[197] we sought comment on this issue in the Proposed Rule to gain insight as to whether such a formulaic approach was appropriate or if providing additional flexibility was a more effective approach. Our review of the comments suggests that most commenters prefer flexible planning criteria for identifying transmission needs not only driven by Public Policy Requirements and evaluation of solutions to those identified needs, but also for the identification and evaluation of transmission needs related to reliability issues and economic considerations as well.[198] These commenters have convinced us that, although there are benefits to each kind of planning criteria, there is merit in allowing for flexible planning criteria to mitigate the possibility that bright line metrics may exclude certain transmission projects from long-term transmission planning.

224. Hence, we will permit public utility transmission providers to include within their

[197] *See, e.g.*, *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,265 (2007).

[198] *E.g.*, AWEA; PJM; New York ISO; SPP; WECC; and Westar.

compliance filings in response to this Final Rule any tariff revisions they believe necessary to implement flexible transmission planning criteria, including changes to existing bright line criteria. This could include procedures to address alternating inclusion and exclusion of a single transmission project in a regional transmission plan over successive planning cycles. Because such tariff revisions will be included as part of the compliance filings in response to this Final Rule, they will be submitted pursuant to section 206 of the FPA rather than under section 205. However, those with existing bright line criteria are not required to make this change if they do not wish to do so. As we evaluate the compliance filings to this Final Rule, we also will evaluate both bright line and flexible criteria for whether they permit unjust and unreasonable rates or undue discrimination through planning criteria and whether they will ensure fair consideration of transmission needs driven by Public Policy Requirements as well as by reliability needs and economic considerations.

### B. Nonincumbent Transmission Developers

225. This part of the Final Rule addresses the removal from Commission-jurisdictional tariffs and agreements of provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. To implement the elimination of such rights, we adopt below a framework that requires the development of qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated in the

regional transmission planning process. We further require that any nonincumbent developer of a transmission facility selected in the regional transmission plan have an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. For purposes of this Final Rule, "nonincumbent transmission developer" refers to two categories of transmission developer: (1) a transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, and as we explained in the Proposed Rule, an "incumbent transmission developer/provider" is an entity that develops a transmission project within its own retail distribution service territory or footprint.[199]

226. We conclude these reforms are necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable, or otherwise result in undue discrimination by public utility transmission providers. As discussed in detail below, our focus here is on the set of transmission facilities that are evaluated at the

[199] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

regional level and selected in the regional transmission plan for purposes of cost allocation, and not on transmission facilities included in local transmission plans that are merely "rolled up" and listed in a regional transmission plan without going through a needs analysis at the regional level (and therefore, not eligible for regional cost allocation). Similarly, our reforms are not intended to affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, nor to alter an incumbent transmission provider's use and control of an existing right of way.

227. In developing the framework below, we have sought to provide flexibility for public utility transmission providers in each region to propose, in consultation with stakeholders, how best to address participation by nonincumbents as a result of removal of the federal right of first refusal from Commission-jurisdictional tariffs and agreements. However, we note that nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. Public utility transmission providers must establish this framework in consultation with stakeholders and we encourage stakeholders to fully participate.

### 1. Need for Reform Concerning Nonincumbent Transmission Developers

#### a. Commission Proposal

228. As discussed above, Order No. 890 sought to reduce opportunities for undue discrimination and preference in the provision of transmission service. With regard to the transmission planning process, the Commission established nine transmission planning principles to prevent undue discrimination. However, Order No. 890 did not specifically address the potential for, or effect of, undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes. The Commission observed in the October 2009 Notice[200] that, as a result of existing practices in some areas, a nonincumbent transmission developer may lose the opportunity to construct its proposed transmission project to the incumbent transmission owner if that owner has a federal right of first refusal to construct any transmission facility in its service territory. The October 2009 Notice sought comment whether such a federal right of first refusal for incumbent transmission owners unreasonably impedes the development of merchant and independent transmission and, if so, how that impediment could be addressed.

229. Based on the comments received, the Commission determined that if a regional

[200] Federal Energy Regulatory Commission, Notice of Request for Comments; Transmission Planning Processes under Order No. 890; Docket No. AD09-8-000, October 8, 2009 (October 2009 Notice).

transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents that regional transmission planning process cannot meet the Order No. 890 transmission planning principle of being "open." Moreover, the Commission stated that such regional planning process may not result in a cost-effective solution to regional transmission needs, and transmission projects in a regional transmission plan therefore may be developed at a higher cost than necessary.[201] As a result, regional transmission services may be provided at rates, terms and conditions that are not just and reasonable. In addition, the Commission determined in the Proposed Rule that there appeared to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission explained that, where an incumbent transmission owner has a federal right of first refusal, a nonincumbent transmission developer risks losing its investment to develop a transmission project that it proposed in the regional transmission planning process, even if the transmission project that the nonincumbent transmission developer proposed is in a regional transmission plan. The Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process under these circumstances.

230. To address these issues, the Commission proposed to reform provisions in public

[201] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87-88.

utility transmission providers' OATTs or other agreements subject to the Commission's jurisdiction that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities that are in a regional transmission plan.

**b. Comments**

231. A number of commenters support the Commission's proposal to address federal rights of first refusal in Commission-jurisdictional tariffs and agreements.[202] For example, Federal Trade Commission states that the existence of a federal right of first refusal in jurisdictional tariffs and agreements reduces capital investment opportunities for potential nonincumbent developers by increasing their risk, encourages free ridership among incumbent developers, and creates a barrier to entry. A number of state utility commissions and consumer advocates agree, arguing that such provisions impede transmission development and that removing the provisions would provide a level

[202] *E.g.*, Federal Trade Commission; American Antitrust Institute; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; American Forest & Paper; DC Energy; Elmer John Tompkins; EIF Management; 26 Public Interest Organizations; and Boundless Energy; Pennsylvania PUC; Connecticut & Rhode Island Commissions; Northern California Power Agency; Eastern Massachusetts Consumer-Owned System; and Transmission Dependent Utility Systems; Arizona Corporation Commission; New Jersey Board; and California PUC; NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

playing field for incumbent and nonincumbent transmission developers.[203]

232. For example, California Department of Water Resources states that competition among transmission providers that promotes efficiencies and innovation should be supported in regulatory policy and transmission planning. New Jersey Board, Connecticut & Rhode Island Commissions and Massachusetts Departments support the proposal to remove a federal right of first refusal, also stating that competition among project sponsors will result in lower cost approaches to meeting system needs. They caution, however, that equal rights must be followed by equal responsibilities and obligations at the federal, regional, state and local level. New England States Committee on Electricity contends that increased competition about which entity will build transmission facilities could help improve cost controls over time. Pennsylvania PUC supports the proposal to eliminate undue discrimination against nonincumbent transmission developers and the attempt to eliminate some of the barriers to full participation by nonincumbent transmission developers. Pennsylvania PUC cautions the Commission, however, to continue to respect Pennsylvania PUC's statutory responsibility to review and approve the siting of transmission projects located in Pennsylvania. Ohio Commission agrees that eliminating rights of first refusal has merit

[203] *E.g.*, Arizona Corporation Commission; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New Jersey Board; Massachusetts Departments; Ohio Consumers Counsel; Pennsylvania PUC; and West Virginia Consumer Advocate.

to the extent that parameters are established to ensure that ratepayers see cost savings and enhanced reliability. Ohio Consumers' Counsel and West Virginia Consumer Advocate Counsel state that eliminating barriers to participation can encourage additional transmission development that could be constructed at lower cost to consumers. Arizona Corporation Commission supports the removal of rights of first refusal, but states that it does not see this as having an impact on an incumbent utility's obligations to serve or affecting the transmission planning process currently utilized in Arizona.

233. Some commenters representing transmission-dependent and municipal utilities express support for the Commission's proposal.[204] Transmission Dependent Utility Systems state that a right of first refusal can prevent or delay construction of needed transmission facilities proposed by nonincumbent transmission developers and also can be used to block transmission access for generation resources that are not associated with the incumbent transmission provider. Northern California Power Agency states that any entity, whether an investor-owned utility, municipal entity, or independent developer, should have the right to propose, construct, and own transmission projects, subject to minimum safety and reliability requirements. Eastern Massachusetts Consumer-Owned System states that eliminating the right of first refusal should help open the door to

[204] *E.g.*, Eastern Massachusetts Consumer-Owned System; Northern California Power Agency; Transmission Agency of Northern California; and Transmission Dependent Utility Systems.

municipal utility participation in transmission ownership on a larger scale.

234. Others supporting the proposal include entities representing independent developers of transmission and generation.[205] NextEra states that allowing the right of first refusal to continue would impede development of innovative transmission solutions in that a transmission project is unlikely to advance very far if its developer cannot be confident that it can see the transmission project to its completion. Clean Line supports the elimination of the right of first refusal and states that encouraging the participation of nonincumbent transmission developers in the regional transmission planning process would increase competition and expand development, which can ultimately lead to lower costs for ratepayers. LS Power states that a right of first refusal and all other discriminatory rules should be eliminated from transmission planning processes inside and outside of RTOs and ISOs.[206] Pattern Transmission states that rights of first refusal and similar preferences favoring incumbent transmission owners do not result in transmission rates that are just and reasonable, are inherently preferential and unduly discriminatory, and suggests that the right of first refusal allows incumbent transmission

[205] *E.g.*, NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

[206] LS Power citing *Primary Power, LLC,* 131 FERC ¶ 61,015 (2010) (*reh'g pending*); *Central Transmission, LLC v. PJM Interconnection L.L.C.*, 131 FERC ¶ 61,243 (2010).

owners to engage in gaming. Primary Power contends that removing a right of first refusal from all Commission-jurisdictional tariffs and agreements would provide an opportunity for a wider variety of technical and financial resources to participate in transmission infrastructure development. Western Independent Transmission Group contends that the ability of incumbent transmission owners to construct transmission projects proposed by other transmission developers under a right of first refusal is equivalent to the seizure of intellectual property.

235. Some commenters cite to examples that they believe show the benefits of removing barriers to competition by nonincumbent transmission developers. For example, Western Independent Transmission Group points to the success of Texas's Competitive Renewable Energy Zone planning process in supporting transmission development by nonincumbent developers. Also, Western Independent Transmission Group points to the Trans Bay Cable, Neptune, and Cross Sound Cable transmission projects, which were developed by nonincumbent transmission developers. Pattern Transmission cites the benefits associated with increased competition in the telecommunications and railroad industries, arguing that comparable benefits are available in the electric industry.

236. Some commenters supporting the Commission proposal argue that the record in this proceeding is sufficient to support taking action at this time. Primary Power states that Commission is "not required to make specific findings so long as the agency's

factual determinations are reasonable."[207] LS Power states that the Commission has legal authority to address discrimination against prospective transmission owners, it has a substantial record that rights of first refusal are unreasonable and result in undue discrimination, thus satisfying the *National Fuel* standard.

237. Commenters supporting the Proposed Rule generally contend that the elimination of rights of first refusal in Commission-jurisdictional tariffs and agreements would not be in conflict with the responsibilities of incumbent transmission providers, such as the obligation imposed under RTO and ISO membership agreements to build transmission facilities identified as needed in regional transmission plans.[208] These commenters state that, to the extent that an incumbent transmission owner feels unreasonably burdened by its obligations to build, a nonincumbent transmission developer would welcome the opportunity to respond to competitive solicitations to build the obligatory transmission projects. Such commenters further note that, as independent transmission developers build transmission projects and become transmission owners themselves, they also may be subject to appropriate obligations to build adjacent or connecting transmission

[207] Primary Power cites to *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000).

[208] *E.g.*, Anbaric and PowerBridge; Green Energy and 21st Century; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; Primary Power; Transmission Agency of Northern California; and Western Independent Transmission Group.

facilities. Northwest & Intermountain Power Producers Coalition states that an incumbent's service obligation would come into play only if no alternative proposal is available to meet the identified need and that, where better alternatives are identified in the planning process, there is no good reason to prevent the better alternative from being constructed merely because the incumbent has an obligation to construct where a better alternative does not exist. Western Independent Transmission Group suggests that the obligation to build is a benefit, not a burden, because an incumbent transmission developer that constructs a transmission project pursuant to an obligation will receive full cost-of-service recovery, including a fair rate of return on its investment.

238. Others urge the Commission to provide thoughtful consideration to the potential impacts of its proposal.[209] Energy Future Coalition states that, while a right of first refusal should not give incumbent utilities the ability to block or stall construction of needed infrastructure within their service territories, or to inflate the costs of such projects, transmission goals will be frustrated if elimination of such provisions bogs down the transmission planning process. New England Transmission Owners state that, before taking action to eliminate any right of first refusal, the Commission should consider the unique way in which transmission projects are identified for development, the success of the current planning process, and the unique characteristics of the New

[209] *E.g.*, Energy Future Coalition; New England Transmission Owners; and MidAmerican.

England system that make the current process appropriate for this region. National Rural Electric Coops suggest that, prior to proceeding with the proposed reforms, the Commission consider adoption of principles to allow load-serving entities to participate in projects developed by traditional and independent transmission providers and to have the right to acquire an ownership participation in any project that it built within their service territories.

239. A number of commenters oppose any alteration of rights of first refusal in Commission-jurisdictional tariffs and agreements, arguing that there is insufficient evidence to justify removal of the right of first refusal.[210] Edison Electric Institute states that, on the contrary, there has been substantial evidence submitted to the Commission that a right of first refusal benefits consumers and results in lower rates, evidence that the Commission has not sought to rebut. Southern California Edison alleges that the Commission provides nothing more than speculative and vague statements that a right of first refusal may preclude nonincumbent transmission developers from participating in the regional transmission planning process and, in turn, affect rates for transmission service. ITC Companies contend that a right of first refusal is not the primary barrier to new market entrants and that they see no impediment to nonincumbent transmission

[210] *E.g.*, California ISO; SPP; CapX2020 Utilities; Edison Electric Institute; Southern California Edison; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; PSEG Companies Comments; and San Diego Gas & Electric.

developers pursuing development opportunities through a partnership model whereby right of first refusal rights are delegated. Oklahoma Gas & Electric notes that a number of transmission-only companies have announced significant transmission projects in SPP and, joined by MISO Transmission Owners, argues that it is premature for the Commission to determine that further reforms are needed to further encourage development.

240. Citing *National Fuel*,[211] some commenters argue that the Commission points to no evidence of actual discrimination or adverse impact on rates and that it must identify something more than theoretical possibilities to justify elimination of federal rights of first refusal.[212] Indicated PJM Transmission Owners assert that, if the Commission intends to rely solely on the effects of potential discrimination, in the absence of evidence of abuse, it must explain why the historical right of incumbent transmission owners to construct additions in their service territories so endangers open access to transmission service at just and reasonable rates as to justify a complete rearrangement of the relationship between public utilities, state regulators, and ultimate customers. MISO

[211] *National Fuel*, 468 F.3d 831.

[212] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Indicated PJM Transmission Owners; Large Public Power Council; MidAmerican; MISO Transmission Owners; Oklahoma Gas & Electric; PSEG Companies; Salt River Project; and San Diego Gas & Electric. Large Public Power Council also cites to *Associated Gas Distributors*.

Transmission Owners state that the Proposed Rule fails to demonstrate why the existing complaint procedures under section 206 do not protect third parties from such theoretical harm.

241. Many of these commenters argue that preserving a federal right of incumbent transmission owners to build within their service territories is the best method to achieve the Commission's overall transmission goals. Such commenters contend that incumbent transmission owners are better situated to build new transmission facilities.[213] For example, Oklahoma Gas & Electric argues that incumbent transmission owners are often in the best position to determine where new transmission is needed on their system. CapX2020 Utilities and MidAmerican state that load serving transmission providers have a long history and relationship with state regulatory bodies that brings value to getting needed transmission developed. Ad Hoc Coalition of Southeastern Utilities and Southern Companies contend that incumbent transmission owners are better situated to obtain any necessary approval from state regulators to recover the cost of transmission facilities through bundled retail tariffs and that nonincumbent developers may have no obligation or ability to do so, depriving the state of an opportunity to determine that the proposal is the most reliable and cost-effective alternative. Ad Hoc Coalition of Southern Utilities

[213] *E.g.*, PJM; CapX2020 Utilities; Edison Electric Institute; Georgia Transmission Corporation; MidAmerican; Omaha Public Power District; Pacific Gas & Electric; Sunflower and Mid-Kansas; and Transmission Access Policy Study Group.

adds that a nonincumbent developer's lack of a funding mechanism based on retail rates is a function of the state-based ratemaking process, not a preference for incumbent transmission owners.

242. Other commenters question the potential impact removal of a federal right of first refusal may have on transmission rates.[214] North Dakota & South Dakota Commissions argue that there is no evidence to suggest that nonincumbents are better situated to provide lower cost or more reliable service, and note that nonincumbents are not regulated by state commissions and not subject to state law obligations regarding reliability or state law oversight of their operations. Alabama PSC states concern that the proposed elimination of the incumbent's federal right of first refusal could increase costs to Alabama consumers. Edison Electric Institute argues that the Commission's proposal ignores longstanding policy that a public utility's investment is assumed to be prudent when a range of options are available, arguing that the Proposed Rule would have a reasonable rate depend upon the identity of the builder of the transmission facility.

243. Some commenters argue that any lower costs that result from competition to own and construct transmission projects is likely to be more than offset by inefficiencies

[214] *E.g.*, Alabama PSC; City of Santa Clara; Dominion; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; PSEG Companies; Southern California Edison; Sunflower and Mid-Kansas; and Xcel.

created in the transmission planning process and a loss of economies of scale and scope.[215] Pacific Gas & Electric states that competition may have cost impacts to incumbent transmission owners relating to their obligation to maintain or improve reliability and security of the existing transmission system to comply with current and future reliability standards. Southern Companies contend that consumers bear the risk of nonincumbent developers declaring bankruptcy or becoming unable or unwilling to complete a transmission project, suggesting that the Commission require "step in" rights in such circumstances to facilitate an incumbent transmission owner's assumption of the project, should it voluntarily choose to do so. Transmission Dependent Utility Systems state that the proposal could raise costs by causing customers outside of an RTO/ISO region to pay both the full costs of the incumbent transmission provider's transmission system and the full incremental costs of any nonincumbent transmission projects necessary to serve its load.

244. Indicated PJM Transmission Owners assert that, even if a nonincumbent were to propose a less expensive transmission project for recovery through cost-based rates, there is no assurance that its final costs will be equal to or lesser than its estimate, or that it has a greater likelihood of staying within its cost estimate than an incumbent transmission owner. They contend that the Commission misapplies cost-effectiveness principles to

[215] *E.g.*, Dominion; PSEG Companies; North Dakota & South Dakota Commissions; and Oklahoma Gas & Electric Company.

non-rate matters beyond its authority, without factual or logical support. PPL Companies agree, arguing that consumers will bear the risk of cost overruns by nonincumbent transmission developers. California ISO notes that the Trans Bay Cable, cited by Western Independent Transmission Group, had significant cost overruns, and that the Neptune and Cross Sound Cable transmission projects were merchant transmission projects that, as direct current transmission lines, involved fewer concerns about system compartmentalization and fragmentation. Southern California Edison states that under the Proposed Rule, there does not appear to be any incentive for project participants to develop cost-efficient proposals because it is not clear if and how customer costs would be considered in project selection.

245. Several comments suggest that the proposal is based on a false assumption that providing for greater competition in the provision of transmission development will produce benefits to consumers.[216] They state that unlike generation, a competitive model cannot be adopted for wholesale transmission because customers have no meaningful alternative transmission provider and the development cycle for transmission is much longer than for generation. California ISO disagrees that the benefits of competition cited by Western Independent Transmission Group and Pattern Transmission are relevant to its transmission planning process. PPL Companies similarly argues that commenters

[216] *E.g.*, California ISO; Indianapolis Power & Light; Oklahoma Gas & Electric Company; and Pacific Gas & Electric.

arguing that eliminating the right of first refusal benefits competition misunderstand the nature of the transmission planning process, noting that RTO planning processes do not involve price competition or consumer choice. PPL Companies contend that eliminating the right of first refusal would not add choice for consumers since the transmission projects included in RTO plans are driven by needs, and not by proposals from incumbent or nonincumbent developers.

246. A number of commenters assert that removing a federal right of first refusal would complicate and undermine the transmission planning process.[217] Delaware PSC states that the Proposed Rule would fundamentally change the way transmission facilities are proposed, selected, and built, and requires thoughtful consideration of all its implications. MISO states that placing regional planners in a role of deciding who should build introduces a level of financial competition to the planning process that is fundamentally at odds with the high level of openness and collaboration under the current approach. Kansas City Power & Light and KCP&L Greater Missouri contend that the proposal would exacerbate an already complex and arduous process to study, plan and implement regional transmission infrastructure. Dominion states that eliminating a federal right of

[217] *E.g.*, AEP; Allegheny Energy Companies; Baltimore Gas & Electric; Dominion; Edison Electric Institute; First Energy Service Company; Indianapolis Power & Light; Kansas City Power & Light and KCP&L Greater Missouri; MidAmerican; MISO; MISO Transmission Owners; Pacific Gas & Electric; and Southern California Edison.

first refusal would create a model where competitively sensitive information will be withheld from open discussion, thus making the planning process less collaborative. Xcel agrees that the proposal could harm the planning process and that disagreements about transmission project selection could have negative impacts on state-level siting and routing approval processes.

247. Some commenters caution that implementation of the proposed reforms could have unintended consequences affecting reliability.[218] These commenters generally contend that eliminating federal rights of first refusal could cause, or exacerbate, operational and reliability challenges for transmission system operations and could produce operational issues as each transmission provider will have to coordinate with more entities to address specific reliability issues. Many of these commenters contend that increasing the number of entities involved in transmission ownership and grid operations would make coordination, maintenance, and service restoration more difficult by further fragmenting the transmission system, which they note has been a concern of the Commission in the past.

248. Several commenters contend that the right of first refusal is inextricably linked to the obligation to build imposed under RTO and ISO membership agreements, justifying

[218] *E.g.*, Baltimore Gas & Electric; California ISO; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; Pacific Gas & Electric; PJM; PSEG Companies; Southern California Edison; and Xcel.

any difference in treatment between incumbent transmission owners and nonincumbent transmission developers.[219] These commenters generally argue that retention of an obligation to build without a corresponding right of first refusal would impose a serious and unjust and unreasonable burden on incumbent transmission owners and is in violation of the FPA. Some state commissions express concern that the Commission's proposal may undermine the ability of utilities to meet their load service obligations.[220] Other commenters state that it is important to maintain an obligation to build for its transmission owning members to ensure transmission projects needed for reliability can be developed promptly.[221] Some commenters contend that the Commission's proposed reforms would result in undue discrimination against incumbent utilities, giving nonincumbent transmission developers the opportunity to propose and build a transmission facility, whereas incumbents would be required to build any needed transmission facility, including those that may be abandoned or not completed by the

[219] *E.g.*, ISO New England; PJM; SPP; Federal Trade Commission; SPP; MISO Transmission Owners; Edison Electric Institute; Georgia Transmission Corporation; Indianapolis Power & Light; Large Public Power Council; Nebraska Public Power District; Arizona Public Service Company; Oklahoma Gas & Electric; MidAmerican; PSEG Companies; San Diego Gas & Electric; Southern California Edison; Tucson Electric; Xcel; Allegheny Energy Companies; Duke; Baltimore Gas & Electric; Dominion; E.ON; Exelon; Westar Integrys; and FirstEnergy Service Company.

[220] *E.g.*, Florida PSC; Minnesota PUC; and Minnesota Office of Energy Security.

[221] *E.g.*, ISO New England; MidAmerican; and MISO Transmission Owners.

nonincumbent developer.[222] Many of these commenters contend this would permit nonincumbent transmission developers to "cherry pick" only the most advantageous projects in terms of financial reward and development risk.[223] Southern California Edison contends that the Commission's proposal amounts to establishing a free call on a utility's capital without any return to compensate it for the time period in which that capital had to be held in reserve to meet a backstop obligation to build.

249. Several commenters express concern about the impact that removing a federal right of first refusal in Commission-jurisdictional tariffs and agreements may have on RTO and ISO participation.[224] For example, MISO states that the right of its transmission owner members to build transmission facilities identified through the planning process was, and remains, one of the key considerations for its transmission owners to have formed, and to remain a part of, the voluntary RTO. MISO Transmission Owners argue that the Proposed Rule would result in undue discrimination between transmission owners voluntarily participating in RTOs and transmission owners that have

[222] *E.g.*, Baltimore Gas & Electric; Edison Electric Institute; FirstEnergy Service Company; Large Public Power Council; MidAmerican; MISO Transmission Owners; PPL Companies; PSEG Companies; and Xcel.

[223] *E.g.*, Baltimore Gas & Electric; California ISO; CapX2020 Utilities; Indianapolis Power & Light; Oklahoma Gas & Electric; Southern California Edison; and Xcel.

[224] *E.g.*, MISO; MISO Transmission Owners; Edison Electric Institute; Alliant Energy; MidAmerican; and Indianapolis Power & Light.

not joined an RTO. MISO Transmission Owners state that, without a right to construct new transmission facilities within their own systems, a transmission owner could experience substantial erosion of its revenues over time as a result of RTO participation. MISO Transmission Owners add that construction obligations and rights in RTOs and ISOs have been carefully designed to ensure that RTOs, ISOs, and their members can comply with all applicable state and federal service obligations and reliability standards. Southern Companies state that the Commission should clarify that the reforms relating to nonincumbent transmission developers do not apply in non-RTO regions. On the other hand, Transmission Agency of Northern California emphasizes that the Commission's proposal to remove a right of first refusal from all Commission-approved tariffs and agreements should apply in both non-RTO/ISO and RTO/ISO regions.

250. Some commenters argue that the existence of native load and state franchise obligations further distinguish incumbent transmission owners from nonincumbent transmission developers, justifying retention of federal rights of first refusal.[225] These commenters assert that nonincumbent developers are not similarly situated because they

[225] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Large Public Power Council; MISO Transmission Owners; Nebraska Public Power District; Xcel; PPL Companies; and Xcel. In support, Ad Hoc Coalition of Southeastern Utilities cites to *California Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 369 (2007); *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, at P 36 (2006); and *Sebring Utils. Comm'n v. FERC*, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979). MISO Transmission Owners also cite to *S. Cal. Edison Co.*, 59 FPC 2167, 2185-86 (1977).

can select the transmission projects they wish to pursue and ignore those they deem too risky or insufficiently profitable, unencumbered by a "duty to serve" requiring the construction and maintenance of facilities necessary to render reliable, cost-effective service to customers in their service territories. For example, Baltimore Gas & Electric states that it and others view their licensed obligations to protect their service territory from power outages as being paramount over their mere financial interests. Edison Electric Institute and MISO Transmission Owners argue that differing state law obligations have been found to be legitimate factors in determining that two entities are not similarly situated.[226] San Diego Gas & Electric contends that removal of federal rights of first refusal raises constitutional concerns since, as regulated entities, public utility transmission providers are entitled under well-established law to receive a reasonable rate of return on their investment in transmission infrastructure in discharging their state-mandated service obligations.[227]

251. A number of commenters suggest that the Commission consider partial elimination of federal rights of refusal.[228] Many of these commenters endorse SPP's

[226] Edison Electric Institute and MISO Transmission Owners cite to *Town of Norwood v. FERC*, 202 F.3d 392, 403 (1st Cir. 2000).

[227] San Diego Gas & Electric supports these assertions by citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works v. Public Serv. Comm'n*, 262 U.S. 679 (1923).

[228] *E.g.*, California PUC; Transmission Dependent Utility Systems; SPP; AEP;

(continued…)

current mechanism, under which an incumbent utility has a 90-day time limit to exercise its right to construct a facility included in the regional transmission plan. AEP suggests that the Commission consider a phased approach, beginning with a time limit on the exercise of any right of first refusal and, if this does not substantially address the Commission's concerns, then consider further modification or elimination of the right of first refusal. AEP suggests that the Commission also could require each region to report back to the Commission within two years on its experience implementing the time-limited right of first refusal as a basis for the Commission to consider whether a fundamental change of the existing regional transmission planning process is needed. California PUC and Exelon argue that incumbent transmission owners should maintain the right of first refusal for reliability projects located within a single zone. Transmission Access Policy Study Group recommends that the Commission retain a limited right of first refusal that can be exercised only when the incumbent transmission provider forgoes transmission incentives for the project and offers meaningful joint ownership opportunities on reasonable terms. Other commenters disagree with proposals to maintain limited rights of first refusal, generally arguing that such proposals would

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Iberdrola Renewables; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; Southern California Edison; Westar; Xcel; CapX2020 Utilities; and SPP.

perpetuate the entry barrier.[229]

252. Finally, some commenters suggest that the Commission engage in additional outreach on this issue before altering federal rights of first refusal.[230] They encourage the Commission to host a technical conference or initiate other proceedings so that all of these issues can be examined and potential solutions developed in a collaborative manner. Sunflower and Mid-Kansas contend that, if problems relating to a right of first refusal exist in a particular region, the issue should be addressed locally rather than imposing a one-size-fits-all solution across all regions.

### c. Commission Determination

253. The Commission concludes that there is a need to act at this time to remove provisions from Commission-jurisdictional tariffs and agreements that grant incumbent transmission providers a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation.[231] Failure to do

[229] *E.g.*, American Antitrust Institute; Anbaric and PowerBridge; LS Power; NextEra; Pattern Transmission; and Western Independent Transmission Group.

[230] *E.g.*, Delaware PSC; NextEra; San Diego Gas & Electric; and Tucson Electric.

[231] As explained in more detail in section III.B.3below, the Commission purposely refers to "federal rights of first refusal" in this Final Rule because the Commission's action on this issue in this Final Rule addresses only rights of first refusal that are created

(continued…)

so would leave in place practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. The Commission addresses the need for eliminating such practices in this section and, in the sections that follow, our legal authority to do so and the procedures by which public utility transmission providers must implement the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

254. As the Commission recognized in Order Nos. 888 and 890, it is not in the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply.[232] In Order No. 890, the Commission required greater coordination in transmission planning on a regional level to remedy the potential for undue discrimination by transmission providers that have an incentive to

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by provisions in Commission-jurisdictional tariffs or agreements. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. This Final Rule does not require removal of references to such state or local laws or regulations from Commission-approved tariffs or agreements.

[232] Order No. 888, FERC Stats. & Regs. at 31,682; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

avoid upgrading transmission capacity with interconnected neighbors where doing so would allow competing suppliers to serve the customers of the public utility transmission provider.[233] Although basing its actions on its authority to remedy undue discrimination, the Commission found that "[t]he coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis."[234]

255. In response to Order No. 890, regions across the country have implemented transmission planning processes that allow for consideration of alternative transmission projects proposed at the regional level to determine if they better meet the region's needs.[235] The evaluation of alternative transmission solutions at the regional level is often referred to as "top down" planning.[236] In some regions, heavy emphasis is placed on "top down" regional planning for all or certain classes of transmission facilities. In other regions, local transmission plans are developed in which individual public utility transmission providers within the region identify solutions to their own local needs prior

[233] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[234] *Id.*

[235] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890-A, FERC Stats. & Regs. ¶ 61,297 at P 215-16. Sponsors of generation and demand response solutions are provided comparable opportunities to offer their proposals in the regional transmission planning process. *Id.*

[236] *See, e.g.*, Pacific Gas & Electric Initial Comments describing top down planning.

to the "top down" consideration of regional alternatives. This is often referred to as "bottom up, top down" planning.[237] Although the relative weight placed on "bottom up" or "top down" processes varies by region, all of these existing processes allow at some point for transmission project developers to offer alternative solutions for evaluation on a comparable basis pursuant to criteria that is set forth in the public utility transmission providers' OATTs.[238] By requiring the comparable evaluation of all potential transmission solutions, the Commission has sought to ensure that the more efficient or cost-effective solutions are in the regional transmission plan.[239]

256. The Commission is concerned that the existence of federal rights of first refusal may be leading to rates for jurisdictional transmission service that are unjust and unreasonable. Allowing federal rights of first refusal to remain in Commission-jurisdictional tariffs and agreements would undermine the consideration of potential transmission solutions proposed at the regional level. Just as it is not in the economic self-interest of public utility transmission providers to expand transmission capacity to

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[237] *See, e.g.*, Large Public Power Council Initial Comments describing bottom up planning.

[238] *See, e.g.*, Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[239] *See, e.g.*, *Northwestern Corp.*, 128 FERC ¶ 61,040, at P 38 (2009); *El Paso Electric Co.*, 128 FERC ¶ 61,063, at P 15 (2009); *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044, at P 35 (2009).

allow access to competing suppliers, it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs. We conclude that an incumbent transmission provider's ability to use a right of first refusal to act in its own economic self-interest may

discourage new entrants from proposing new transmission projects in the regional transmission planning process.

257. Federal rights of first refusal exacerbate these problems by, as the Federal Trade Commission and other commenters explain, creating a barrier to entry that discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level. Many commenters note that significant investment is needed to support the development of a successful transmission project, yet there is a disincentive for a nonincumbent transmission developer to commit its resources to a potential transmission project when it runs the risk of an incumbent transmission provider exercising its federal right of first refusal once the benefits of the transmission project are demonstrated. The Commission recognizes that removing federal rights of first refusal in Commission-jurisdictional tariffs and agreements will not eliminate all obstacles to transmission development that may exist under state or local laws or regulations and, therefore, may not address all challenges facing nonincumbent transmission development

in those jurisdictions. It does not follow, however, that the Commission should leave in place federal rights of first refusal. Moreover, the number of state commission commenters supporting the Commission's proposal indicate that, at a minimum, there is interest in those jurisdictions to explore the benefits of nonincumbent transmission development.

258. The Commission shares the concerns of some commenters that elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, if not implemented properly, could adversely impact the collaborative nature of current regional transmission planning processes. The Commission addresses these concerns in section III.B.3 by modifying and clarifying the proposed framework for implementing our reforms, including elimination of the proposed requirement to allow a transmission developer to maintain for a defined period a right to build and own a transmission facility. In addition, this Final Rule does not require removal of a federal right of first refusal for a local transmission facility, as that term is defined herein.[240] The Commission disagrees with commenters asserting that reforming federal rights of first refusal would fundamentally alter regional transmission planning processes. Public utility transmission providers already are required to evaluate whether alternative transmission solutions proposed by other developers better meet the needs of the region.

[240] *See* definition *supra* section II.D of this Final Rule.

Therefore, existing regional transmission planning processes have mechanisms in place to weigh various alternatives against one another. Indeed, this is the fundamental nature of "bottom-up, top-down" transmission planning, in which local needs and solutions are combined within a region and analyzed to determine whether regional solutions would be more efficient or cost-effective than the local solutions identified by individual public utility transmission providers.[241]

259. The Commission understands that the degree to which existing transmission planning processes will be impacted by the elimination of federal rights of first refusal will vary by region, just as the current mechanisms used to evaluate competing transmission projects vary by region. For example, the public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit projects or project developers to meet regional needs. To the extent a region already has in place processes to rely on market proposals or competitive solicitations when identifying solutions to the region's needs, such existing processes may require relatively modest modifications to provide nonincumbent transmission providers with the opportunity to propose and construct transmission projects, consistent with state and local

[241] Similarly, the Commission believes that concerns regarding the cost-effectiveness of nonincumbent transmission development are misplaced. For one solution to be chosen over another in the transmission planning process, there must be an evaluation of the relative economics and effectiveness of performance for each alternative. *See, e.g., New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044 at P 35, n.26.

laws and regulations. In regions relying more heavily on local planning with less robust mechanisms to identify alternative transmission solutions at the regional level, more effort may be needed to implement the Commission's reforms. Within the implementation framework adopted below, the Commission provides each region with the flexibility necessary to identify the modifications to existing transmission planning processes that may be required as a result of removing federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

260. The Commission is not persuaded to abandon our proposed reforms to federal rights of first refusal based on arguments that incumbent transmission providers are better situated to build and operate transmission facilities. While we acknowledge that incumbent transmission providers may have unique knowledge of their own transmission systems, familiarity with the communities they serve, economies of scale, experience in building and maintaining transmission facilities, and access to funds needed to maintain reliability, we do not believe removing the federal right of first refusal diminishes the importance of these factors. An incumbent public utility transmission provider is free to highlight its strengths to support transmission project(s) in the regional transmission plan, or in bids to undertake transmission projects in regions that choose to use solicitation processes. However, we do not believe that, just because an incumbent public utility transmission provider may have certain strengths, a nonincumbent transmission

developer should be categorically excluded from presenting its own strengths in support of its proposals or bids.

261. Various commenters argue that federal rights of first refusal are inextricably tied to obligations to build placed on incumbent transmission providers, such as those under RTO and ISO member agreements. We acknowledge that a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO or ISO, but we do not believe that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region. There are many benefits and obligations associated with membership in an RTO or ISO and an obligation to build at the direction of the RTO or ISO is only one aspect of the agreement. While implementation of reforms to federal rights of first refusal may change the package of benefits and burdens currently in place for transmission owning members of RTOs and ISOs, we find that such changes are necessary to correct practices that may be leading to rates for jurisdictional transmission service that are unjust and unreasonable.

262. Some commenters also contend that the federal right of first refusal is necessary for incumbent transmission providers to develop transmission facilities needed to comply with a reliability standard or an obligation to serve customers. We clarify that our actions today are not intended to diminish the significance of an incumbent transmission

provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint. The Final Rule continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation. Alternatively, an incumbent transmission provider may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation. Our decision today does not prevent an incumbent transmission provider from continuing to propose transmission projects for consideration in the regional transmission planning process and to receive regional cost allocation if those projects are selected in a regional transmission plan for such purposes, even if they are located entirely within its retail distribution service territory or footprint,

263. Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations. To avoid this result, in section III.B.3 below, we require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the

regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations.

264. One function of the regional transmission planning process is to identify those transmission facilities that are needed to meet identified needs on a timely basis and, in turn, enable public utility transmission providers to meet their service obligations. Given the familiarity incumbent transmission providers have with their own systems, we expect that they will continue to participate actively in the regional transmission planning process to share their unique perspectives regarding whether various potential solutions meet particular needs of their systems. To the extent an incumbent transmission provider has concerns that a regional transmission alternative does not address the identified reliability needs or service obligations that would allow it to serve its customers reliably to meet state or local laws, whether upon initial evaluation or, as relevant, subsequent reevaluation, it can make such concerns known so that all relevant information regarding a regional transmission alternative can be considered.

265. The Commission disagrees that elimination of federal rights of first refusal would result in discrimination against incumbent transmission providers in favor of nonincumbent transmission developers. Once a member of an RTO or ISO, a

nonincumbent transmission developer will be subject to the relevant obligations that apply to the RTO or ISO members. While it is true that the obligation of nonincumbent transmission developers to expand their transmission facilities, once within an RTO or ISO, may apply to fewer transmission facilities than those of an incumbent with a large footprint, and that some incumbent transmission providers may be subject to different requirements under state and local laws, it does not follow that eliminating federal rights of first refusal amounts to discrimination in favor of nonincumbent transmission developers. Rather, we are merely removing a barrier to participation by all potential transmission providers. With regard to concerns that our reforms will discourage entities from joining or maintaining membership in RTOs and ISOs, we note that a variety of factors must be weighed when evaluating the benefits and burdens of RTO/ISO membership. In addition, we reject Southern Companies' request that we clarify that the reforms related to nonincumbent transmission developers do not apply in non-RTO regions; the reforms apply equally to public utility transmission providers in all regions. The Commission believes that the modifications and clarifications provided below with regard to the framework under which transmission developers will participate in the transmission planning process will alleviate some of the concerns expressed by commenters.

266. We are not persuaded by commenters who argue that the reliability of the transmission system is a function of the number of public utility transmission providers

of that system. In fact, to enhance reliability, among other reasons, public utility transmission providers have historically connected to the transmission systems of others, as well as jointly owned transmission facilities, and have therefore developed experience, protocols, and business models for coordinated operations with multiple transmission providers, operators, and users. Moreover, many of the same commenters that raise reliability concerns also suggest that nonincumbent transmission developers instead pursue the merchant model of development, which similarly increases rather than decreases the number of transmission providers within a region. All providers of bulk-power system transmission facilities, including nonincumbent transmission developers, that successfully develop a transmission project, are required to be registered as functional entities and must comply with all applicable reliability standards.[242] Together with the additional requirements we adopt in section III.B.4 below, the Commission finds these protections sufficient to support our decision here to eliminate the federal rights of first refusal contained in Commission-jurisdictional tariffs and agreements.

267. The Commission recognizes that there may be circumstances when an incumbent transmission provider may be called upon to complete a transmission project that it did not sponsor. For example, a situation may arise where an incumbent transmission provider is called upon to complete a transmission project that another entity has

[242] 18 CFR Part 39.2(a) (2011).

abandoned. There also may be situations in which an incumbent transmission provider has an obligation to build a project that is selected in the regional transmission plan for purposes of cost allocation but has not been sponsored by another transmission developer. We clarify that both of these situations would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA. In addition, the Commission addresses reliability concerns that may arise under those circumstances below.

268. For the foregoing reasons, and in light of the evaluation procedures required in section III.B.3 below, the Commission finds that there is sufficient justification in the record to implement the requirements regarding rights of first refusal contained in Commission-jurisdictional tariffs or agreements. The Commission is not required to identify specific evidence to justify our actions today. Our task in this respect is to show that there is "'ground for reasonable expectation that competition may have some beneficial impact.'"[243] Although the Commission has previously accepted, in some cases, and rejected, in others, a federal right of first refusal, we find more persuasive in light of the comments in this proceeding, the Commission's reasoning in rejecting the federal right of first refusal. In particular, the Commission rejected a right of first refusal

[243] *Wisconsin Gas Company v. FERC*, 770 F.2d 1144, 1158 (D.C. Cir. 1985) (citing *FCC v. RCA Communications, Inc.*, 346 U.S. 86, 96 (1953)).

based on an expectation that "[t]he presence of multiple transmission developers would lower costs to customers."[244] We have carefully considered the record in the proceeding and therefore find further procedures to evaluate the need for the reforms adopted herein to be unnecessary.

269. Finally, we disagree with San Diego Gas & Electric that the elimination of a federal right of first refusal raises concerns under *FPC v. Hope Natural Gas Co.* and *Bluefield Water Works v. Public Serv. Comm'n*. As San Diego Gas & Electric notes, these cases stand for the principle that utilities are entitled to receive a reasonable return on their investment. They do not, however, speak to the issue of who may make an investment. They thus require only that a utility receive a reasonable rate of return on the investments that it makes, not that the utility receive a preferential right to make those investments.

### 2. Legal Authority To Remove a Federal Right of First Refusal

#### a. Commission Proposal

270. In the Proposed Rule, the Commission explained that the existing planning process

[244] *Cleco Power LLC*, 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings*, 112 FERC ¶ 61,069 (2005); *see also Carolina Power and Light Co.*, 94 FERC ¶ 61,273 at 62,010, *order on reh'g*, 95 FERC ¶ 61,282 at 61,995 (2001) (finding that a federal right of first refusal would unduly limit the planning authority and present the possibility of discrimination by self-interested transmission owners, potentially reduce reliability, and possibly precluding lower cost or superior transmission facilities or upgrades by third parties from being planned and constructed).

may not result in a cost-effective solution to regional transmission needs and transmission projects that are in a regional transmission plan therefore may be developed at a higher cost than necessary. The Commission stated that the result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.[245] The Commission also stated that it may be unduly discriminatory or preferential to deny a nonincumbent public utility transmission developer that sponsors a project that is in a regional transmission plan the rights of an incumbent public utility transmission developer that are created by a public utility transmission provider's tariffs or agreements subject to the Commission's jurisdiction. Under these circumstances, the Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. The Commission stated that, if the regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents, it cannot meet the principle of being "open."

#### b. Comments Regarding the Commission's Authority To Implement the Proposal

271. Several commenters argue that the Commission has adequate statutory authority to undertake the reforms in the Proposed Rule.[246] Some of the commenters supporting the

[245] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87-88.

[246] *E.g.*, Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; Multiparty Commenters; and Primary Power.

Commission's proposal to eliminate federal rights of first refusal from Commission-jurisdictional tariffs and agreements specifically addressed the scope of the Commission's authority under section 206 of the FPA. Primary Power contends that the Commission is authorized under section 206 to remove or limit the right of first refusal, which is a rule, practice, or contract condition subject to its jurisdiction. Primary Power states that, while the proposal to eliminate the right of first refusal represents a change in the Commission's policy of tolerance or occasional acceptance of the right of first refusal, this change in policy is justified as in the public interest. Primary Power argues that rights of first refusal are creatures of regulated services that are subject to federally-regulated tariffs and, therefore, proponents of rights of first refusal must find some independent legal basis for the property rights they seek to protect.

272. LS Power argues that the Commission has a duty to stamp out all forms of discrimination in the form of a right of first refusal, whether written in the OATT or other agreement, or simply as part of a long-standing bias arising from a closed planning process. LS Power contends that eliminating rights of first refusal is a critical step toward true competition in the electric industry, and essential to ensuring that new transmission infrastructure is provided to consumers at just and reasonable rates. LS Power notes that the Commission has historically required the elimination of provisions

that are anticompetitive on their face.[247] Joined by American Forest & Paper, LS Power further argues that elimination of a federal right of first refusal would not be inconsistent with existing state laws, noting the support for the Commission proposal by a number of state commissions submitting comments.

273. Other commenters contend that the Commission does not have the legal authority to implement the proposed reforms related to rights of first refusal in Commission-jurisdictional tariffs or agreements. Some commenters argue that the FPA does not give the Commission the authority to address discrimination between incumbent and nonincumbent transmission developers, arguing that the FPA's protection against undue discrimination is concerned with the protection of consumer interests and does not extend to nonincumbent transmission developers.[248] Ad Hoc Coalition of Southeastern Utilities states that precedent shows that the rights of competitors are neither protected nor contemplated in FPA section 205(b)'s proscription against undue discrimination.[249]

[247] LS Power (citing *Gulf States Utils. Co.*, 5 FERC ¶ 61,066 (1978)).

[248] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; Nebraska Public Power District; Omaha Public Power District; Xcel; and Indicated PJM Transmission Owners (citing *Grand Council of the Crees v. FERC*, 198 F.3d 950, 956 (D.C. Cir. 2000)).

[249] Ad Hoc Coalition of Southeastern Utilities cites to *Brunswick Corp. v. Pueblo*

(continued…)

Edison Electric Institute agrees, arguing that an undue discrimination analysis in the context of the right of first refusal provisions and planning processes is unsupportable, explaining that such provisions are not rates, terms, and conditions of a service that a transmission owner provides to its customers. Edison Electric Institute states that the Commission previously has not taken the step of characterizing transmission planning as an obligation or service to non-customers to facilitate their competing efforts to own transmission facilities. Edison Electric Institute further states that the comparability analysis for undue discrimination could not apply because ownership is not a service that a transmission owner provides to itself.

274. Indicated PJM Transmission Owners contend that the undue discrimination concerns underlying Order. No. 888, regarding access to transmission facilities for loads and for competing suppliers of wholesale electricity, are not present here. Indicated PJM Transmission Owners argue the Commission does not and cannot find that relying on incumbent transmission owners to build necessary upgrades to their systems discriminates either in the terms of service available to different classes of transmission customers or in the terms upon which wholesale sellers and buyers gain access to the transmission system.

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*Bowl-O-Mat, Inc.*, 429 U.S. 477, 487-89 (1977), *Cargill, Inc. v. Montfort of Colorado, Inc.*, 479 U.S. 104, 115-17 (1976), *City of Frankfort v. FERC*, 678 F.2d 699, 707 (7th Cir. 1982).

275. Some commenters analogize to the Commission's jurisdiction under section 205 of the FPA, arguing that there are only two types of undue discrimination actionable under section 205: treating similar customers differently or affording similar treatment to dissimilar customers.[250] Some of these commenters assert that the court in *City of Frankfort v. FERC*[251] noted that section 205 provisions focus on the fair treatment of customers. Similarly, Nebraska Public Power District states *Public Service Commission of Indiana*[252] stands for the proposition that the antidiscrimination policy in section 205(b) is violated where one consumer has its rates raised significantly above what other similarly situated consumers are paying.

276. Other commenters also argue that the Commission lacks general jurisdiction over the siting, construction, or ownership of transmission facilities, matters they assert Congress intentionally left to the states, as demonstrated by a comparison between the FPA and the Natural Gas Act.[253] Commenters assert that the proposal to adopt rules

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[250] *E.g.*, Nebraska Public Power District; Large Public Power Council; and MISO Transmission Owners. Some of these commenters cite to *Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27-28 (D.C. Cir. 1984), *Sacramento Mun. Util. Dist. v FERC*, 474 F.3d 797, 802 (D.C. Cir. 2007), *City of Vernon v. FERC*, 845 F.2d 1042, 1046 (D.C. Cir. 1988), *Ohio Power Co. v. FERC*, 744 F.2d 162, 165 n.3 (D.C. Cir. 1984), and *"Complex" Consol. Edison Co. v. FERC*, 165 F.3d 992, 1012 (D.C. Cir. 1999).

[251] *City of Frankfort v. FERC*, 678 F.2d 699, 704 (7th Cir. 1982).

[252] *Pub. Serv. Comm'n of Indiana, Inc. v. FERC*, 575 F.2d 1204, 1213 (7th Cir. 1978).

[253] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power

(continued…)

governing who can build transmission within an incumbent transmission owner's zone exceeds the authority conferred upon the Commission under the FPA to regulate the terms and conditions of service and, in essence, create a federal franchise for transmission service.[254]

277. Other commenters argue that the Commission is provided only limited backstop siting authority under section 216 of the FPA, a grant of authority that the courts have emphasized is subservient to the primary jurisdiction of the states.[255] Oklahoma Gas & Electric Company argues that, in enacting section 215 of the FPA, Congress expressly declined to grant the Commission the authority to require the construction of facilities or the expansion of the grid. PPL Companies contend that the Commission's jurisdiction under FPA sections 210 and 211 to order existing utilities to enlarge their facilities, if necessary to permit transmission service or interconnection, can be invoked only pursuant to specific procedures and after specific findings are made.

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District; Oklahoma Gas and Electric Company; Omaha Public Power District; PPL Companies; Large Public Power Council; Xcel; Indianapolis Power & Light; Edison Electric Institute; Indicated PJM Transmission Owners; and Virginia State Corporation Commission. Indicated PJM Transmission Owners cite to *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996).

[254] *E.g.*, PPL Companies and PSEG Companies.

[255] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Indicated PJM Transmission Owners; Oklahoma Gas & Electric Company; and PPL Companies. Indicated PJM Transmission Owners cite to *Piedmont Envtl. Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).

278. Oklahoma Gas & Electric Company asserts that, for the Commission to extend its jurisdiction over actions that indirectly affect activity otherwise governed by the states, the Commission must show that the action in question has a direct and significant effect on jurisdictional rates. Oklahoma Gas & Electric Company argues that the courts are unwilling to allow the Commission to regulate activity if, in so doing, the Commission is directly regulating activity that was specifically reserved for the states.[256] Oklahoma Gas & Electric Company cites to *National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 395, 401 (D.C. Cir. 2004), where the court found that Commission regulations related to generator interconnection procedures bore a close enough relationship to its authority over jurisdictional transmission services that the exercise of jurisdiction over interconnection service was permissible.

279. Commenters opposing the Commission's proposed reforms generally reject the notion that the Commission is acting only to eliminate the federal right of first refusal, stating that the Proposed Rule would go much farther by regulating the protocols for determining the entity responsible to construct an upgrade. Indicated PJM Transmission Owners argue that, to the extent a state-created right is reflected in an RTO or ISO tariff or agreement, it cannot then be converted by the Commission into a federal based right

[256] Oklahoma Gas & Electric Company (citing *Northwest Central Pipeline Corp. v. State Corp. Comm'n of Kansas*, 489 U.S. 493 (1989); *Connecticut Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 484 (D.C. Cir. 2009); *Mississippi Indus. v. FERC*, 808 F.2d 1525, 1542-43 (D.C. Cir. 1987)).

that the Commission can eliminate by its own regulation. Indicated PJM Transmission Owners assert that the fact that the transmission provider may be an RTO or ISO does not expand the Commission's jurisdiction because the transmission owner is still the public utility that makes and supports financial investments. They argue that the Commission cannot use such a voluntary association to require utilities to surrender their statutory rights, in accordance with *Atlantic City Electric Co. v. FERC*.[257]

280. Other commenters similarly agree that not every provision of a Commission-jurisdictional rate schedule or tariff governs the terms and conditions of jurisdictional services.[258] For example, PPL Companies argues that there are numerous provisions in agreements required to be filed with the Commission that are not rates or other terms or conditions that affect rates, such as provisions addressing force majeure and indemnification. PPL Companies and others point to provisions in transmission owner agreements or RTO operating agreements that establish governance as an example of terms that are beyond the Commission's jurisdiction.[259] Indicated PJM Transmission Owners argue that, consistent with *CAISO v. FERC*, section 206 is not implicated because the building and owning of an upgrade is not a practice or contract that affects a

[257] 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City*).

[258] *E.g.*, Oklahoma Gas & Electric; and PPL Companies. In support, Oklahoma Gas & Electric Company cites to *PSI Energy, Inc.*, 55 FERC ¶ 61,254, at 61,811 (1991), *reh'g denied*, 56 FERC ¶ 61,237 (1991).

[259] PPL Companies (citing *CAISO v. FERC*, 372 F.3d 395 (D.C. Cir. 2004)).

rate, charge, or classification for transmission. Indicated PJM Transmission Owners argue that regulation of the determination of which entity constructs transmission additions and expansions is a regulation of whether the utility can provide a service at all, not the rate for the service. Indicated PJM Transmission Owners explain that *CAISO v. FERC* noted that the FPA provides the Commission with limited power regarding corporate governance in section 305, which involves interlocking directorates, and this supports the proposition that section 206 was not intended to reach such matters.[260]

281. Indicated PJM Transmission Owners contend that each of the choices a utility's management makes potentially constitutes a "practice" that eventually affects rates insofar as the utility seeks to recover the resulting costs. If the Commission concludes that an investment or other business decision is the product of imprudent management, Indicated PJM Transmission Owners contend that the Commission has authority to consider denying recovery of excessive costs resulting from that decision, not to supplant the public utility's management's decision-making authority.[261] Joined by FirstEnergy Service Company, Indicated PJM Transmission Owners argue that a fundamental

[260] In addition, FirstEnergy Service Company states that the court in *CAISO v. FERC* explained that a more expansive interpretation of "practice" would allow the Commission to regulate a range of subjects that the court considered to be plainly beyond the Commission's authority.

[261] Indicated PJM Transmission Owners (citing *Town of Norwood v. FERC*, 80 F.3d 526, 531 (D.C. Cir. 1996)).

premise of the FPA is that a utility has a right to recover prudently incurred costs, and a corollary of this principle is that a utility must have the right to decide whether to make those investments.[262]

282. Indicated PJM Transmission Owners disagree with the Commission's statement that the regional transmission planning processes that do not consider and evaluate of projects proposed by nonincumbent transmission developers cannot meet the principle of being "open." They argue that the Commission cannot, by relying upon nondiscrimination principles, bootstrap authority it does not have for mandating the sponsorship model. Citing *Office of Consumers' Counsel v. FERC*,[263] Indicated PJM Transmission Owners argue that the Commission cannot redefine the transmission planning principles adopted in Order No. 890 to encompass matters that were never contemplated when it was issued. Indicated PJM Transmission Owners assert that nothing about the transmission owners' construction rights and obligations prohibits parties from participating in the process or proposing transmission projects. They state that the Commission has offered no rationale for concluding that the requirement of

[262] Indicated PJM Transmission Owners (citing *Mo. ex. rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n*, 262 U.S. 276, 289 n.1 (1923)). Indicated PJM Transmission Owners also note that Congress did provide similar authority in laws that parallel the FPA, such as section 402 of the Transportation Act of 1920, and sections 5 and 7 of the Natural Gas Act.

[263] *Office of Consumers' Counsel v. FERC*, 655 F.2d 1132, 1148 (D.C. Cir. 1980).

openness must be redefined to include a new sponsorship model.

283. National Grid notes that the rights and obligations of transmission owners in New England to own and construct transmission facilities or upgrades located within or connected to their existing electric systems were extensively litigated in the proceeding where the Commission found that ISO New England satisfied the requirements to be an RTO. National Grid states that in that proceeding, the Commission-approved contractual language in Section 3.09 of ISO New England's Transmission Operating Agreement providing that, absent agreement of ISO New England and the participating transmission owners to an amendment to these provisions, they will be subject to the *Mobile-Sierra* doctrine. Therefore, National Grid argues that the subject provisions cannot be modified by the Commission unless it finds they are contrary to the public interest. It submits that there is no evidence to meet this high standard. National Grid requests that Commission should either clarify that Commission-approved rights to build of transmission owners like those in New England would not be affected by the proposed NOPR requirements, or modify those requirements in the Final Rule to allow transmission owners in New England to continue to meet regional needs under the existing planning process.

### c. Commission Determination

284. The Commission determines that it has the authority under section 206 of the FPA to implement the reforms adopted to eliminate provisions in Commission-jurisdictional tariffs and agreements that grant federal rights of first refusal to incumbent transmission

providers with respect to the construction of transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission's remedial authority under FPA section 206 of the FPA is broad and allows us to act, as we do here, to revise terms in jurisdictional tariffs and agreements that may cause the rates, terms or conditions of transmission service to become unjust and unreasonable or unduly discriminatory or preferential.[264] As explained in the preceding section, granting incumbent transmission providers a federal right of first refusal with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation effectively restricts the universe of transmission developers offering potential solutions for consideration in the regional transmission planning process. This is unjust and unreasonable because it may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, the inclusion of higher-cost solutions in the regional transmission plan. It is squarely within our authority under FPA section 206 to correct this deficiency.

285. A federal right of first refusal is, in the language of section 206(a), a "rule, regulation, practice, or contract" affecting the rates for jurisdictional transmission service. Where the Commission finds that such rules, regulations, practices or contracts are "unjust, unreasonable, unduly discriminatory, or preferential," the Commission must determine "the just and reasonable rate, charge, classification, rule, regulation, practice,

[264] *Associated Gas Distributors*, 824 F.2d 981, 1008 (D.C. Cir. 1985).

or contract to be thereafter observed and in force, and shall fix the same by order." In light of our finding above that federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings, the Commission is compelled under section 206(a) to take corrective action here. The court in *CAISO v. FERC* explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and "not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so."[265] The Commission here is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on competition and in turn the rates for jurisdictional transmission services. As explained in greater depth below, these matters fall directly within the ambit of the court's interpretation of a practice affecting rates.

286. In addition, federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission has long recognized that it has a responsibility to consider anticompetitive practices and to

[265] *CAISO v. FERC*, 372 F.3d 395 at 403.

eliminate barriers to competition.[266] Indeed, the Supreme Court has said that "the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[267] In requiring the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, we are acting in accordance with our duty to maintain competition.

287. Eliminating a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, as some commenters contend, result in the regulation of matters reserved to the states, such as transmission construction, ownership or siting. The reforms are focused solely on public utility transmission provider tariffs and agreements subject to the Commission's jurisdiction. While many commenters indicate that they disagree with these statements, none of them has explained adequately how our actions will override or conflict with state laws or regulations. The Commission acknowledges that there may be restrictions on the construction of transmission facilities by nonincumbent transmission providers under rules or regulations enforced by other jurisdictions. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities,

[266] *Gulf States Utils. Co.*, 5 FERC ¶ 61,066 at 61,098.

[267] *Otter Tail Power Co. v. United States*, 410 U.S. 366 at 374 (1973).

including but not limited to authority over siting or permitting of transmission facilities. It does not follow that the Commission has no authority to remove such restrictions in the tariffs or agreements subject to its jurisdiction.

288. The Commission disagrees with commenters arguing that the effect of a federal right of first refusal on jurisdictional rates is too tenuous to support action. These commenters argue that the holding of *CAISO v. FERC*,[268] prevents us from treating a federal right of first refusal as a practice that affects transmission rates. In that case, the court held that the Commission has no authority to replace the selection method or membership of the governing board of the California ISO, which had been established under state law.[269] The court found that such internal governance practices were too remote from the California ISO's rate structure to be considered practices that affect rates for purposes of section 206 and, as a result, rejected the Commission's attempt to impose governance requirements that conflicted with state law.[270]

289. Here, however, the Commission is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on the rates for jurisdictional transmission services and on undue discrimination. This extends well beyond the internal corporate governance matters at issue in *CAISO v. FERC*. The

[268] 372 F.3d 395 at 399.

[269] *CAISO v. FERC*, 372 F.3d 395 at 398.

[270] *Id.* at 403.

federal rights of first refusal at issue in this proceeding can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs and, as a result, increasing the cost of transmission development that is recovered from jurisdictional customers through rates. The selection of transmission facilities in a regional transmission plan for purposes of cost allocation is therefore, unlike corporate governance matters, directly related to costs that will be allocated to jurisdictional ratepayers.

290. Other commenters rely on *Mo. ex. rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n* for the proposition that, because a utility has a right to recover prudently incurred costs, it has a corollary right to decide whether to incur those costs, which the Commission cannot violate by eliminating a federal right of first refusal. In that case, the court explained that a utility's right to make investment decisions is grounded in the business judgment rule, which prevents courts from substituting their judgment on the prudence of investment decisions for that of corporate directors and officers.[271] Nothing in that case, however, supports a claim to an exclusive right to make investments under a federal right of first refusal, only the need to defer to business judgment when investment decisions are in fact made. In removing a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is drawing no conclusion regarding

[271] *See Mo. ex. rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n*, 262 U.S. 276, 289 (1923).

the prudence of any investment decision, nor is the Commission seeking to determine which particular entity should construct any particular transmission facility. The effect of these reforms is to allow more types of entities to be considered for potential construction responsibility, not to make choices among those transmission developers or their proposed transmission facilities.

291. The Commission therefore determines that these reforms regarding elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements are not prevented by state law or otherwise limited by the FPA. In directing the removal of a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is not ordering public utility transmission providers to enlarge their transmission facilities under sections 210 or 211 of the FPA, nor making findings related to our authorities under section 215 or 216. Similarly, nothing in our actions today is inconsistent with our obligations under section 217. Indeed, section 217(b)(4) directs the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load serving entities to satisfy [their] load serving obligations." Greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load serving entities and increased access to resources.

292. We decline to address at this time the merits of National Grid's arguments that

section 3.09 of the ISO New England Transmission Operating Agreement establishes a federal right of first refusal that can be modified only if the Commission makes the findings that National Grid contends are required by application of the *Mobile-Sierra* doctrine. [272] We find that the record is not sufficient to address the specific issues raised by National Grid in this generic proceeding. Moreover, we generally do not interpret an individual contract in a generic rulemaking, and we are not persuaded to do so here given the limited record developed so far on section 3.09. Thus, we conclude that these arguments, including National Grid's argument as to the applicable standard of review, are better addressed as part of the proceeding on ISO New England's compliance filing pursuant to this Final Rule, where interested parties may provide additional information.

### 3. Removal of a Federal Right of First Refusal from Commission-Jurisdictional Tariffs and Agreements

#### a. Commission Proposal

293. In the Proposed Rule, the Commission sought comment on a framework to eliminate from a transmission provider's OATT or agreements subject to the Commission's jurisdiction provisions that establish a federal right of first refusal for an

[272] In support of its argument, National Grid cites *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 78 (2004). In that order, the Commission stated, "We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides direction to the Transmission Owners and the ISO-NE RTO to follow planning procedures contained in the ISO-NE RTO OATT. As such, this provision will have no adverse impact on third parties or the New England market."

incumbent transmission provider with respect to transmission facilities that are included in a regional transmission plan. The Commission proposed to require each public utility transmission provider to revise its OATT to: (1) establish appropriate qualification criteria for determining an entity's eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer; (2) include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process, and provide a single, specified date by which proposals must be submitted; (3) describe a transparent and not unduly discriminatory or preferential process used by the region for evaluating whether to include a proposed transmission facility in a regional transmission plan; (4) remove, along with corresponding changes in any other Commission-jurisdictional agreement, provisions that establish a federal right of first refusal for an incumbent transmission provider and include a description of how the regional transmission planning process provides a right to construct a selected project to the project sponsor, including potential modifications to proposed projects; (5) provide the right to develop a project for a defined period of time if not initially included in a regional transmission plan; and, (6) provide a comparable opportunity for incumbent and nonincumbent

transmission project developers to recover the cost of a transmission facility through a regional cost allocation method.[273]

294. Under this framework, the Commission proposed that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. The Commission stated that both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan. The Commission proposed that the tariff changes to implement these proposed reforms would be developed through an open and transparent process involving the public utility transmission provider, its customers, and other stakeholders.

295. Given the interrelated nature of comments regarding the first two and the remaining four elements of the Commission's proposed framework, the Commission groups comments accordingly and then turns to addressing the comments collectively.

### b. Comments Regarding Developer Qualification and Project Identification

296. A number of commenters address issues related to the first two aspects of the Commission's proposed framework, governing mechanisms by which entities could

[273] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 90-96.

propose a project in the regional transmission planning process.[274] San Diego Gas & Electric contends that any qualification criteria for potential transmission developers should address all of the technical and financial capabilities necessary for the entity to support the transmission project, if approved, for its expected lifetime, including provisions of security and insurance, as well as other requirements, such as those relating to the proponent's capital structure. Wind Coalition agrees that transmission project developers should be required to satisfy certain financial standards to ensure that they can properly construct and maintain their proposed projects. According to Wind Coalition, the experience of the Competitive Renewable Energy Zones in ERCOT has demonstrated the need for a selection procedure that provides for: clearly defined standards for selection; selection within a reasonable time period; and a definite beginning and ending date to avoid unnecessary delay in selection and construction and to prevent a strategy of delay or gamesmanship.

297. Most commenters that weighed in on this issue urge the Commission not to adopt a one-size-fits-all set of requirements and, instead, allow each region to develop criteria

[274] *E.g.*, American Transmission; Connecticut & Rhode Island Commissions; Federal Trade Commission; Integrys; ISO-NE; Large Public Power Council; MidAmerican; Massachusetts Departments; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; New Jersey Board; NextEra; Northeast Utilities; and Western Independent Transmission Group.

appropriate for the region.[275] A number of commenters, however, encourage the Commission to identify the types of criteria that must be addressed to codify expectations and ensure that all entities are operating under the same requirements.[276] Old Dominion recommends that the following criteria be used to evaluate proposers of projects: financial viability; technical expertise; authority or ability to obtain and meet all necessary regulatory requirements, including condemnation where necessary; and an exit strategy to address how the facilities can or will be transferred if an entity is no longer able to meet financial or other obligations associated with the project. PJM supports a requirement that each project developer demonstrate that it has received up-front authority to site its project from the relevant states because, without such authority, it would be fruitless to designate a project to the prospective project developer. In reply, however, Atlantic Wind Connection disagrees with PJM, instead suggesting that developers receive state siting approval within a reasonable time after selection of the project in a regional transmission plan.

298. While many commenters endorse requiring project developers to meet qualification criteria showing their financing and technical capabilities, some argue that

[275] *E.g.*, New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[276] *E.g.*, Edison Electric Institute; California ISO; Pacific Gas & Electric; Exelon; Southern California Edison; Southern Companies; PJM; and National Grid.

the rules cannot be one-sided against nonincumbents so as to amount to a backdoor right of first refusal.[277] LS Power states, for example, that an entity that is financially qualified but is deemed to not be technically qualified should be permitted to partner with a technically qualified entity. Pattern Transmission states that, if a transmission provider determines that a project developer does not meet the qualification criteria, it should be required to provide the rationale for that determination to the applicant in writing so that any future attempt to meet the qualification criteria will be better informed. Other commenters express concern that the qualification criteria not be so onerous that they cannot be readily satisfied by existing transmission owners.[278] APPA and Transmission Access Policy Group suggest that qualification criteria be crafted in a way that supports a variety of ownership arrangements, including joint ownership by public power systems.

299. Some commenters oppose or otherwise raise concerns regarding the use of qualification criteria to determine eligibility to propose projects in the regional transmission planning process.[279] PPL Companies state that RTOs do not have experience in evaluating the capabilities of nonincumbent transmission developers and

[277] *E.g.*, Anbaric and PowerBridge; LS Power; and Pattern Transmission; and Primary Power. Anbaric and PowerBridge cite to *New England Indep. Transmission Co., L.L.C.*, 118 FERC ¶ 61,127 (2007).

[278] *E.g.*, New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[279] *E.g.*, PPL Companies; Indianapolis Power & Light; and Pacific Gas & Electric.

that both the establishment and application of the criteria are likely to result in disputes and litigation. Indianapolis Power & Light states that, because incumbents have existing state obligations to serve, incumbent transmission owners should be deemed to meet any qualification criteria without any additional showing. Pacific Gas & Electric similarly argues that qualification criteria should take into consideration the ability of incumbent transmission owners to provide cost and efficiency benefits that may not be available from a single-project transmission owner, such as in obtaining siting and permitting approvals.

300. Several commenters address the use of a form to obtain information from prospective transmission developers as to projects submitted for evaluation in the regional transmission planning process.[280] LS Power asks the Commission to set forth the requisite project information required in such a form, subject to any region or transmission provider obtaining Commission approval to modify such requirements. California ISO suggests that, notwithstanding its general opposition to the elimination of federal rights of first refusal, any requirements imposed on project developers to submit information in support of a proposal should include the submission of sufficient study results evidencing a *prima facie* case that the project is needed. Exelon contends that project proposals should be required to include technical analyses demonstrating that they

[280] *E.g.*, California ISO; Edison Electric Institute; LS Power; and Transmission Agency of Northern California.

meet the region's requirements and that a developer should not be provided with any priority rights without such supporting documentation. Transmission Agency of Northern California asks the Commission to clarify that the evaluation form should be developed in the regional transmission planning process and that a project developer would not be required to submit separate and distinct forms to each public utility transmission provider that participates in a given regional transmission planning process.

301. LS Power supports the proposal for public utility transmission providers to identify a specified date by which to submit proposed transmission projects, generally arguing that a submission deadline would promote orderly and fair consideration of projects.[281] Others oppose the proposal, generally arguing that existing transmission planning processes are iterative in nature.[282] For example, New England States Committee on Electricity states that establishing such a deadline could have the unintended consequence of discouraging discussion of emerging needs and alternative ways to meet them. It suggests that the Commission leave such procedural matters to the regions for consideration. Some commenters express concern that the Commission's proposal invites gaming, creating an incentive to propose a host of projects so that

[281] *E.g.*, LS Power.

[282] *E.g.*, Edison Electric Institute; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

individual entities may obtain their own time-based rights of first refusal to develop proposals.[283] LS Power disagrees in reply, arguing that such concerns could be addressed by requiring transmission developers to post a reasonable deposit, which could be based in part on the total estimated cost to develop the annual plan and the number of transmission projects evaluated in the plan, to avoid new projects being filed in an effort to prevent others from developing them.

### c. Comments Regarding Project Evaluation and Selection

302. Commenters also address the remaining four aspects of the Commission's proposed framework for eliminating federal rights of first refusal, relating to mechanisms to evaluate, select and recover the costs of projects proposed in the regional transmission planning process. Most commenters support the proposal that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted through a transparent and not unduly discriminatory or preferential process.[284] For example, Duke and National Grid state that existing regional

[283] *E.g.*, Edison Electric Institute; Exelon; MISO Transmission Owners; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

[284] *E.g.*, Federal Trade Commission; PUC of Nevada; Massachusetts Departments; New England States Committee on Electricity; California Commissions; Connecticut & Rhode Island Commissions; LS Power; FirstWind; National Grid; Western Independent Transmission Group; Transmission Agency of Northern California; Northern California

(continued…)

transmission planning processes already evaluate proposed projects through an open process described in the relevant public utility transmission providers' OATTs.

303. Several commenters suggest that regional flexibility is needed when determining the procedures by which transmission projects are evaluated and selected.[285] For example, Connecticut & Rhode Island Commissions and Massachusetts Departments state that ensuring equal rights and obligations of incumbent and nonincumbent transmission developers would raise a number of questions that will need to be addressed through the stakeholder process, including how projects and developers are selected, how non-transmission alternatives will be evaluated, how rights of way are negotiated, and how to address cost overruns. They state that the Final Rule should recognize the many issues that would arise following the proposed change and allow the stakeholder process flexibility to identify and develop solutions to these challenges. Western Independent Transmission Group suggests the use of an independent third-party observer may be necessary to oversee the evaluation and selection of competing transmission projects to give market participants and the Commission assurance that the process is fairly and efficiently managed.

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Power Agency; Pattern Transmission; American Transmission; California State Water Project; Anbaric and PowerBridge; PPL Companies; Green Energy and 21st Century; Duke; and Old Dominion.

[285] *E.g.*, Connecticut & Rhode Island Commissions; National Grid; New England States Committee on Electricity; KCP&L; Edison Electric Institute; and WIRES.

304. A number of commenters characterize the Commission's proposal as implementing a sponsorship model that conflicts with the collaborative nature of current transmission planning processes.[286] North Dakota & South Dakota Commissions state that the sponsorship paradigm will turn current transmission planning processes into an unmanageable free for all, undermining the effective evaluation of potential transmission solutions. Integrys and Southern Companies contends that sponsorship rights may do more harm than good and will defeat the objective of an orderly and systematic planning and construction process, increasing disputes, creating queuing problems, disrupting existing OATT processes, harming reliability, and resulting in a loss of flexibility. Baltimore Gas & Electric argues that those that want to claim sponsorship rights also do not want to provide the RTO with discretion to deny their claim and that such entities could tie up transmission construction as long as they want until they ensure they are the builders. National Rural Electric Coops suggest that the Commission convene a technical conference to address complex implementation issues.

305. Southern Companies also question how transmission proposals submitted by nonincumbent transmission providers should be evaluated in the regional transmission planning process. Southern Companies state that the Proposed Rule could be viewed as

[286] *E.g.*, Baltimore Gas & Electric; Edison Electric Institute; Integrys; MISO Transmission Owners; North Dakota & South Dakota Commissions; PSEG Companies; PPL Companies; and Southern Companies.

permitting any qualified entity to sponsor projects at the regional level, where a "black box" evaluation process would be applied to determine the "winners." Southern Companies suggest that nonincumbent transmission developers be treated similarly to the integration of merchant generation so that state law would not be undermined. That is, Southern Companies recommend that, if a nonincumbent transmission developer has a proposal that the incumbent utility believes to be cost-effective and reliable, that developer would have to join with Southern Companies to petition the relevant state regulatory authorities for approval for construction and rate recovery.

306. Some commenters argue that the Commission should not require development of mechanisms that provide construction rights to nonincumbent transmission developers seeking to develop projects solely within an existing transmission owner's footprint or that use rights-of-way held by existing transmission owners.[287] For example, Edison Electric Institute asks the Commission to clarify that only an incumbent transmission owner should be allowed to propose local, single system facilities that are simply rolled up into a regional plan, as well as upgrades or modifications to facilities owned by an incumbent transmission provider, including reconductoring, tower change outs, additional facilities in existing substations, facilities in a right of way owned by the

[287] *E.g.*, Anbaric and PowerBridge; California Municipal Utilities; Edison Electric Institute; Exelon; Imperial Irrigation District; LS Power; PJM; and Southern California Edison.

incumbent, and new substations cut into existing lines. It argues that allowing nonincumbent transmission developers to perform upgrades to an incumbent transmission owner's transmission facilities could delay upgrades necessary to maintain system reliability and increase the costs of constructing and maintaining such transmission facilities. PJM agrees, arguing that existing transmission owners are in the best position to use their own resources. Imperial Irrigation District expresses concern regarding the potential impact of the Proposed Rule on contractual rights in existing joint ownership and operation agreements governing existing facilities. LS Power cautions that, to the extent the Commission provides for the retention of federal rights of first refusal for existing facilities, the limitations of such an exclusion must be clearly described in the OATT.

307. A number of commenters suggest that the Commission modify the proposal for sponsors of proposed transmission projects to retain the right to build projects of a similar scope for a defined period of time.[288] Bonneville Power states that this proposed reform creates the potential for increased litigation to determine whether an incumbent transmission owner's project is substantially similar to a previously proposed non-incumbent transmission developer's project. Xcel and others[289] contend that selection

[288] *E.g.*, California Municipal Utilities; Exelon; LS Power; Northern Tier Transmission Group; and Transmission Agency of Northern California.

[289] *E.g.*, Duke; PPL Companies; MidAmerican; and North Dakota and South

(continued…)

among similar projects for inclusion in the regional transmission plan is inherently subjective and, therefore, determining whether a project is a modification of a previously proposed project or sufficiently different to be considered a new project would be difficult. National Rural Electric Coops ask the Commission to clarify that the proposal does not prevent an incumbent transmission provider from making minor modifications to a competing transmission project to better meet the needs of the participants in the process.

308. Some commenters argue that the Commission should implement competitive bidding processes for selecting project developers instead of relying on a sponsor-based mechanism for determining construction rights.[290] For example, Transmission Access Policy Study Group contends that competitive bidding yields lower costs to consumers, includes mechanisms to limit cost overruns, and restricts the ability of winning bidders to transfer construction rights. It suggests that any competitive bidding process employed by the Commission favor projects that are jointly owned. California ISO states that its competitive solicitation framework for economic and public policy transmission projects meets the Commission's goals of ensuring development of cost-effective transmission facilities, providing ratepayer benefits, optimizing participation in the transmission

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Dakota Commissions.

[290] *E.g.*, Transmission Access Policy Study Group; Pattern Transmission; and Indianapolis Power & Light.

planning process, and providing opportunities for nonincumbent transmission developers, although California ISO opposes the use of competitive solicitations for reliability projects. Edison Electric Institute and Ad Hoc Coalition of Southeastern Utilities contend that mandating competitive bidding would undermine existing transmission planning processes and allow nonincumbent developers to bid selectively only for advantageous projects. Pattern Transmission responds that such "cherry picking" concerns can be addressed through properly structured competitive bidding processes.

309. With regard to the period for which development rights could be retained, LS Power recommends that a transmission developer that sponsors a transmission project be permitted to retain the right to build or build and own the transmission project for a minimum of five years, while California Municipal Utilities suggest a period of two years. Others express concern with the impact of the Commission's proposal, generally arguing such a policy would encourage entities to submit multiple proposals to maximize potential development opportunities.[291] For example, National Rural Electric Coops suggest this would create an approach to transmission planning in which immutable transmission proposals compete against each other in a form of baseball arbitration (in which the arbitrator must pick one side's offer without modification), even if minor

[291] *E.g.*, Connecticut & Rhode Island Commissions; Indianapolis Power & Light; Indicated PJM Transmission Owners; Massachusetts Departments; National Rural Electric Coops; and Oklahoma Gas & Electric.

changes to one or more of the proposals would allow them to better meet the needs of consumers in the region. LS Power and Transmission Agency of Northern California disagree, arguing that objective rules can be established to identify when a modified project is the functional equivalent of a sponsored project.

310. Arizona Corporation Commission stresses that, in all cases, proposed transmission projects resubmitted for consideration must be freshly evaluated in each transmission planning cycle so that projects address current needs and requirements. Northern Tier Transmission Group recommends that a project that is not selected in the regional transmission plan must have similar performance characteristics and costs when resubmitted for consideration. California Municipal Utilities argue that a project sponsor should not receive a priority right during resubmission if the transmission project sponsor is only interested in selling that right.

311. Some commenters seek clarification of the obligations that would be imposed on nonincumbent transmission developers as a result of selection of its project for construction.[292] MISO Transmission Owners and New York Transmission Owners contend that, if the proposed reforms are implemented, the Commission should make clear that a nonincumbent transmission developer's right to participate in the

[292] *E.g.*, New York Transmission Owners; Edison Electric Institute; MISO Transmission Owners; Southern Companies; and Transmission Agency of Northern California.

transmission planning process must be accompanied by an obligation that it satisfy all the requirements expected of transmission developers in the regional transmission planning process. MISO Transmission Owners state that this clarification is particularly important because institutional investors may seek to invest in transmission facilities to earn the stable return on their investment that a rate-regulated business would provide but have no intention to become public utilities once the facility is placed into service and put under the functional control of an RTO. Minnesota PUC and Minnesota Office of Energy Security suggest that winning transmission projects, regardless of ownership type, should be subject to regulatory scrutiny to make sure that when completed the transmission project fulfills the needs initially ascribed to it and that the transmission project costs are consistent with the cost levels initially proposed.

312. Finally, commenters also address whether the selection of a transmission facility proposed by a nonincumbent transmission developer for inclusion in the regional transmission plan should be eligible for regional cost allocation.[293] Massachusetts Departments and Connecticut & Rhode Island Commissions agree with the basic principle, but argue that recovery should be determined by project criteria and not on the

[293] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; FirstEnergy Service Company; MISO Transmission Owners; New York ISO; Old Dominion; and SPP.

basis of the type of developer proposing the project. SPP and Old Dominion support the proposal, provided that the nonincumbent transmission developer is subject to the same responsibilities as incumbent transmission owners pursuant to the transmission planning requirements. MISO Transmission Owners raise the possibility that a nonincumbent project selected in the regional transmission planning process may be rejected by a state agency in favor of an incumbent transmission owner and question whether under this scenario an incumbent transmission owner would be required to build the project but would not be eligible for regional cost recovery. Ad Hoc Coalition of Southeastern Utilities assert that the proposal may conflict with state-based mandates, explaining that the majority of transmission costs in the Southeast are incurred to serve native load, and are included in rates established pursuant to state or local regulation.

### d. Commission Determination

313. The Commission directs public utility transmission providers, subject to the modifications to the Proposed Rule discussed below and subject to the framework discussed and adopted below, to eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation.

314. As explained in the preceding sections, the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements is necessary and

appropriate to ensure that rates for jurisdictional services are just and reasonable. However, based on the comments received in response to the Proposed Rule, the Commission modifies the specific requirements placed on public utility transmission providers to implement the proposal and provides clarification regarding those requirements to facilitate compliance.[294]

315. To place our actions in context, the Commission reiterates the existing requirements of Order No. 890 as implemented by public utility transmission providers. As noted by commenters, Order No. 890 already requires public utility transmission providers to have in place processes for evaluating the merits of proposed transmission solutions offered by potential developers.[295] To ensure comparable treatment of all resources, the Commission has required public utility transmission providers to include in their OATTs language that identifies how they will evaluate and select among competing solutions and resources.[296] This includes the identification of the criteria by which the

[294] The requirements adopted here apply only to public utility transmission providers that have provisions in their tariffs or other Commission-jurisdictional agreements granting a federal right of first refusal that is inconsistent with the requirements of this Final Rule. If no such provisions are contained in a public utility transmission provider's tariff or other Commission-jurisdictional agreement, it should state so in its compliance filing.

[295] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890-A, FERC Stats. & Regs. ¶ 61,297 at P 215-16.

[296] *See, e.g.*, *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044 at P 35.

public utility transmission provider will evaluate the relative economics and effectiveness of performance for each alternative offered for consideration.[297] Given that the regions already have processes in place to evaluate competing transmission projects in their transmission planning process, the fundamental question raised in the Proposed Rule is whether additional requirements are needed to ensure that these processes are not adversely affected by federal rights of first refusal. The Commission concludes that such requirements are necessary and, accordingly, adopts the framework set forth in the Proposed Rule with modification.

316. Opponents of the Commission's proposed elimination of federal rights of first refusal argue that this framework represents a fundamental shift in the way that transmission is planned in existing regional processes. These commenters contend that characterizing existing transmission owners as developers of sponsored transmission facilities that are to be evaluated on a comparable basis to proposals submitted by nonincumbent transmission developers transforms, in their view, the collaborative and iterative transmission planning process into a sponsorship-driven competition for new investment opportunities. As we explain elsewhere, the reforms adopted in this Final Rule build upon the requirements of Order No. 890 with respect to transmission planning. Public utility transmission providers already have put in place mechanisms to provide for

[297] *Id.*

comparative evaluation of competing solutions. We recognize that the mechanisms for evaluating proposals under this Final Rule will have greater implications because we are also requiring a just and reasonable and not unduly discriminatory process to grant to a transmission developer the ability to use the regional cost allocation method associated with each transmission facility selected in the regional transmission plan for purposes of cost allocation. However, we disagree that the reforms in the Proposed Rule, as modified herein, will make the planning process unmanageable, as suggested by some commenters.

317. Some of the concerns expressed by commenters appear to be driven by the phrasing used in the Proposed Rule to present the framework for removing federal rights of first refusal. There, the Commission stated that both incumbent and nonincumbent transmission developers should share similar benefits and obligations, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan.[298] The Commission's focus in the Proposed Rule on sponsorship of proposed transmission facilities, whether by incumbent transmission providers or nonincumbent transmission developers, appears to have led many commenters to conclude that every transmission facility being planned by an incumbent transmission provider is, in effect, sponsored by that entity and, therefore, could no

[298] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 93.

longer be subject to a federal right of first refusal. The Commission clarifies that this was not the intent of the Proposed Rule, nor is it the intent of the requirements adopted in this Final Rule.

318. The Commission's focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation.[299] As Edison Electric Institute notes, in those regions relying on "bottom up" local transmission planning, a transmission facility that is in a public utility transmission provider's local transmission plan might be "rolled-up" and listed in a regional transmission plan to facilitate analysis at the regional level. However, the transmission facility from the local transmission plan might not have been proposed in the regional transmission planning process and might not have been selected in the regional transmission plan for purposes of cost allocation by going through an analysis in the regional transmission planning process. The Commission does not, in this Final Rule, require removal from Commission-jurisdictional tariffs and agreements of a federal right of first refusal as applicable to a local transmission facility, as that term is defined

[299] In order for a transmission facility to be eligible for the regional cost allocation methods, the region must select the transmission facility in the regional transmission plan for purposes of cost allocation. For those facilities not seeking cost allocation, the region may nonetheless have those transmission facilities in its regional transmission plan for information or other purposes, and then having such a facility in the plan would not trigger regional cost allocation.

herein.[300] .

319. In addition, the Proposed Rule emphasized that our reforms do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation.[301] In other words, an incumbent transmission provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities. In addition, the Commission affirms that proposal here, and in response to commenters adds that our reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way. That is, this Final Rule does not remove or limit any right an incumbent may have to build, own and recover costs for upgrades to the facilities owned by an incumbent, nor does this Final Rule grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation. The retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way.

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[300] *See* definition *supra* section II.D of this Final Rule.

[301] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 97.

320. Through the reforms to regional planning required in this Final Rule, the Commission is seeking to ensure that a robust process is in place to identify and consider regional solutions to regional needs, whether initially identified through "top down" or "bottom up" transmission planning processes. Combined with the cost allocation and other reforms adopted in this Final Rule, implementation of this framework to remove federal rights of first refusal will address disincentives that may be impeding participation by nonincumbent transmission developers in the regional transmission planning process. The extent to which any existing regional transmission planning process must be changed to implement the framework set forth below will depend on the mechanisms used by the region to evaluate competing transmission projects and developers.

321. For example, this Final Rule permits a region to use or retain an existing mechanism that relies on a competitive solicitation to identify preferred solutions to regional transmission needs, and such an existing process may require little or no modification to comply with the framework adopted in this Final Rule.[302] In regions

[302] For example, the Commission has found that competitive solicitation processes can provide greater potential opportunities for independent transmission developers to build new transmission facilities. *See, e.g.*, *California Indep. Sys. Operator*, 133 FERC ¶ 61,224 (2010). However, the Commission declines to adopt commenter suggestions to mandate a competitive bidding process for selecting project developers. While the Commission agrees that a competitive process can provide benefits to consumers, we continue to allow public utility transmission providers within each region to determine for themselves, in consultations with stakeholders, what mechanisms are most appropriate to evaluate and select potential transmission solutions to regional needs.

relying primarily on "top down" mechanisms pursuant to which regional planners independently identify regional needs and more efficient and cost-effective solutions, existing procedures that allow for stakeholders to offer potential solutions for consideration could provide a foundation for implementing the framework below. In other regions emphasizing the development of local transmission plans prior to analysis at the regional level of alternative solutions, additional procedures may be required to distinguish between those transmission facilities that are proposed to be selected in the regional transmission plan for purposes of cost allocation and those that are merely "rolled up" for other purposes.

322. The Commission concludes that the framework adopted below provides sufficient flexibility for public utility transmission providers in each region to determine, in the first instance, how best to address the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements. Because we are allowing for regional flexibility and encouraging stakeholders to participate fully in the implementation of this framework by public utility transmission providers, we decline to decide in this Final Rule to convene a technical conference to further explore issues related to federal rights of first refusal, as suggested by some commenters. With the foregoing background in mind, the Commission turns to the specific requirements of this framework below.

### i. Qualification Criteria to Submit a Transmission Project for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

323. First, the Commission requires each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer. These criteria must not be unduly discriminatory or preferential. The qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities.

324. The Commission agrees with commenters that qualification criteria are necessary, and that adoption of one-size-fits-all requirements would not be appropriate. It is important that each transmission planning region have the flexibility to formulate qualification criteria that best fit its transmission planning processes and addresses the particular needs of the region. Such criteria could address a range of issues raised by commenters, such as commitments to be responsible for operation and maintenance of a

transmission facility.[303] The Commission stresses, however, that appropriate qualification criteria should be fair and not unreasonably stringent when applied to either the incumbent transmission provider or nonincumbent transmission developers. The qualification criteria should allow for the possibility that an existing public utility transmission provider already satisfies the criteria and should allow any transmission developer the opportunity to remedy any deficiency. Within these general parameters, we leave it to each region to develop qualification criteria that are workable for the region, including procedures for timely notifying transmission developers of whether they satisfy the region's qualification criteria and opportunities to mitigate any deficiencies.[304]

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[303] The Commission notes, however, that nothing in the qualification requirement of this Final Rule precludes a transmission developer from entering into voluntary arrangements with third parties, including any interested incumbent transmission provider, to operate and maintain a transmission facility. Similarly, nothing this Final Rule creates an obligation for an incumbent transmission provider to operate and maintain a transmission facility developed by another transmission developer. Additionally, nothing in the qualifications requirement of this Final Rule is intended to change any existing RTO or ISO procedure or practice regarding the operation of one or more existing transmission facilities.

[304] To be clear, the qualification criteria required herein should not be applied to an entity proposing a transmission project for consideration in the regional transmission planning process if that entity does not intend to develop the proposed transmission project. The Order No. 890 transmission planning requirements allow any stakeholder to

(continued…)

### ii. Submission of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

325. Second, the Commission requires that each public utility transmission provider revise its OATT to identify: (a) the information that must be submitted by a prospective transmission developer in support of a transmission project it proposes in the regional transmission planning process; and (b) the date by which such information must be submitted to be considered in a given transmission planning cycle. The Commission declines to adopt the proposal to require a specific form to be developed for the purpose of submitting this information, given that the data to be submitted may not be easily reduced to entries on a form. To ensure consistency in the region, however, the Commission requires each public utility transmission provider that has its own OATT to have in that OATT the same information requirements as other public utility transmission providers in the same transmission planning region, as requested by Transmission Agency of Northern California.

326. These information requirements must identify in sufficient detail the information necessary to allow a proposed transmission project to be evaluated in the regional transmission planning process on a basis comparable to other transmission projects that

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request that the transmission provider perform an economic planning study or otherwise suggest consideration of a particular transmission solution in the regional transmission planning process.

are proposed in the regional transmission planning process. They may require, for example, relevant engineering studies and cost analyses and may request other reports or information from the transmission developer that are needed to facilitate evaluation of the transmission project in the regional transmission planning process. Beyond these minimum requirements, the Commission provides each region with discretion to identify the information to be required, so long as such requirements are fair and not so cumbersome as to effectively prohibit transmission developers from proposing transmission projects, yet not so relaxed that they allow for relatively unsupported proposals. Whether the region wishes to require *prima facie* showings of need for a project, as suggested by the California ISO, should be addressed in the first instance by public utility transmission providers in consultation with stakeholders within the region. The Commission will review the resulting information requirements on compliance and provide further guidance at that time, if necessary.

327. The Commission disagrees that requiring the identification of a date by which information must be submitted for consideration in a given transmission planning cycle undermines the iterative nature of transmission planning or amounts to creation of a time-based federal right of first refusal. Without some reasonable limitation on the submission of new information, public utility transmission providers would never be able to complete the analysis needed to complete their region's transmission plan. However, each region may determine for itself what deadline is appropriate, including potentially the use of

rolling or flexible dates to reflect the iterative nature of their transmission planning processes. Given our decision to eliminate the proposed ongoing right to develop previously-sponsored transmission projects, the Commission believes it is not necessary to require here additional procedural protections such as the posting of deposits, as suggested by LS Power. To the extent stakeholders in a particular region believe such procedures have merit, they may consider them during the development of OATT proposals that comply with the requirement of this Final Rule.

### iii. Evaluation of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

328. Third, the Commission requires each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation. This process must comply with the Order No. 890 transmission planning principles, ensuring transparency, and the opportunity for stakeholder coordination. The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation. In complying with this requirement, the Commission encourages public utility transmission providers to build on existing regional transmission planning processes that, consistent with Order Nos. 890 and 890-A, already set forth the criteria by

which the public utility transmission provider evaluates the relative economics and effectiveness of performance for alternative solutions offered during the transmission planning process.

329. In light of comments received in response to the Proposed Rule, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations. We appreciate that there are many sources of delay that could affect the timing of transmission development, and do not intend to require constant reevaluation of delays that do not materially affect the ability of an incumbent transmission provider to meet its reliability needs or service obligations. Our focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. Under such circumstances, an incumbent transmission provider must have the ability to propose solutions that it would

implement within its retail distribution service territory or footprint that will enable it to meet its reliability needs or service obligations. If such other solution is a transmission facility, public utility transmission providers in the regional transmission planning process should evaluate the proposed solution for possible selection in the regional transmission planning process for purposes of cost allocation. As we have explained elsewhere in this Final Rule,[305] nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.

330. The Commission appreciates that the selection of any transmission facility in the regional transmission plan for purposes of cost allocation requires the careful weighing of data and analysis specific to each transmission facility and, in some instances, may be difficult or contentious. While the Commission appreciates the challenges presented by such an evaluation, the requirement to engage in a comparative analysis of proposed solutions to regional needs has been in place since Order No. 890. The Commission encourages public utility transmission providers to consider ways to minimize disputes, such as through additional transparency mechanisms, as they identify enhancements to

[305] *See supra* P 256

regional transmission planning processes necessary to comply with this Final Rule.[306] The Commission declines, however, to mandate the use of independent third-party observers, as suggested by Western Independent Transmission Group. To the extent public utility transmission providers in consultation with other stakeholders in a region wish, they may propose to use an independent third-party observer and we will review any such proposal on compliance.

331. By requiring the evaluation of proposed transmission solutions in the regional transmission planning process, the Commission is not dictating that any particular proposals be accepted or that selected transmission facilities be constructed. Similar to the planning requirements of Order No. 890, the Commission requires the establishment of processes to evaluate potential solutions to regional transmission needs, with the input of interested parties and stakeholders. Whether or not public utility transmission providers within a region select a transmission facility in the regional transmission plan for purposes of cost allocation will depend in part on their combined view of whether the transmission facility is an efficient or cost-effective solution to their needs.[307] Moreover,

[306] Additionally, as described in section III.A, the requirements of the dispute resolution principle order of Order No. 890 apply to the regional transmission planning process as reformed by this Final Rule.

[307] As noted above, for one solution to be chosen over another in the regional transmission planning process, there should be an evaluation of the relative efficiency

(continued…)

the Commission anticipates that the processes for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation will vary from region to region, just as other aspects of the regional transmission planning processes may vary.

### iv. Cost Allocation for Projects Selected in the Regional Transmission Plan for Purposes of Cost Allocation

332. The Commission also requires that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation. More specifically, each public utility transmission provider must participate in a regional transmission planning process that provides that the nonincumbent developer has an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. As explained further in section IV.C, the cost of a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region's

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and cost-effectiveness of each solution. If a nonincumbent transmission developer is unable to demonstrate that its proposal is the most efficient or cost-effective, given all aspects of its proposal, then it is unlikely to be selected as the preferred transmission solution within the regional transmission planning process for purposes of cost allocation.

cost allocation method or methods.

333. In the Proposed Rule, the Commission acknowledged that a proposed transmission project can be modified in the regional transmission planning process as needs and potential solutions are analyzed and, therefore, sought comment on whether to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility. Although the Commission raised this issue in the context of processes of construction rights, similar issues are raised regarding the selection of a transmission facility in the regional transmission plan for purposes of cost allocation.

334. In light of the comments received in response to this aspect of the Proposed Rule, we are concerned that the proposed requirement to identify the most similar project to one initially proposed could conflict with the way potential solutions are evaluated and selected in some regions. For example, a requirement to identify proposals that are "most similar" to transmission projects in the regional transmission plan may be meaningless in a region that relies on market proposals or competitive solicitations to identify solutions to the region's needs. In other regions that rely on voluntary construction decisions for transmission facilities in a regional transmission plan, the linking of rights to construct to a determination of similarity may be meaningless. As discussed in the next section, in response to concerns such as these, we have decided not to adopt the proposal that would give a sponsor the federal right to construct and own a transmission facility it sponsored

consistent with state or local laws or regulations. Given this change, we do not adopt the proposal to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility.

335. Instead, we adopt and clarify the requirement that a nonincumbent transmission developer of a transmission facility selected in the regional transmission plan for purposes of cost allocation have the same opportunity as an incumbent transmission developer to allocate the cost of such transmission facilities through a regional cost allocation method or methods. We require that each public utility transmission provider must participate in a regional transmission planning process that makes each transmission facility selected in the regional transmission plan for purposes of regional cost allocation eligible for such cost allocation. In other words, eligibility for regional cost allocation is tied to the transmission facility's selection in the regional transmission plan for purposes of cost allocation and not to a specific sponsor.

336. We also require that public utility transmission providers in a region establish, in consultation with stakeholders, procedures to ensure that all projects are eligible to be considered for selection in the regional transmission plan for purposes of cost allocation. This mechanism could be, for example, a non-discriminatory competitive bidding process. The mechanism a regional planning process implements could also allow the sponsor of a transmission project selected in the regional transmission plan for purposes

of cost allocation to use the regional cost allocation method associated with the transmission project. In that case, however, the regional transmission planning process would also need to have a fair and not unduly discriminatory mechanism to grant to an incumbent transmission provider or nonincumbent transmission developer the right to use the regional cost allocation method for unsponsored transmission facilities selected in the regional plan for purposes of cost allocation. There may also be other mechanisms, or combinations of mechanisms, that may comply with our requirements.

337. The Commission declines commenter requests to further define the particular obligations and responsibilities that may flow from selection of a nonincumbent transmission developer's proposal in the regional transmission plan for purposes of cost allocation. Nothing in this Final Rule is intended to change or limit any obligations that would apply to a nonincumbent transmission developer under state or local laws or under RTO or ISO agreements.

### v. Rights to Construct and Ongoing Sponsorship

338. The Proposed Rule also sought comment on whether to include two additional features in a framework to implement the elimination of federal rights of first refusal: whether to require public utility transmission providers to revise their OATTs to contain a regional transmission planning process that provides a right to construct and own a transmission facility; and, whether to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed

but that is not selected.[308] The Commission declines to adopt these aspects of the Proposed Rule.

339. In the preceding sections, the Commission adopted a framework in which, upon selection of a transmission facility in a regional transmission plan for purposes of cost allocation, the developer of that transmission facility (whether incumbent or nonincumbent) will have the ability to rely on the relevant cost allocation method or methods within the region should it desire to move forward with its transmission project. Nothing in this Final Rule preempts or limits any obligations or requirements that a nonincumbent transmission developer may be subject to under state or local laws or regulations or under RTO or ISO agreements.

340. With regard to ongoing sponsorship rights, the Commission concludes on balance that granting transmission developers an ongoing right to build sponsored transmission projects could adversely impact the transmission planning process, potentially leading to transmission developers submitting a multitude of possible transmission projects simply to acquire future development rights. The Commission appreciates that not granting such a right causes some risk for transmission developers in disclosing their transmission projects for consideration in the regional transmission planning process. That risk is outweighed, however, by the potentially negative impacts such a rule could have on

[308] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 95.

regional transmission planning.

### 4. Reliability Compliance Obligations of Transmission Developers

#### a. Comments Regarding Reliability Obligations

341. PSEG Companies and Indianapolis Power & Light contend that it is unclear how compliance with NERC reliability standards would be managed and whether and to what extent a third-party developer would be responsible for NERC compliance, coordination of outages, and whether it would need to become a member or transmission owner in an RTO. PSEG Companies also assert that third party developers are not regulated by state commissions and are not subject to state law obligations with respect to reliability and safety or state law oversight of their operations. Salt River Project argues that mandatory compliance with NERC reliability standards places added pressure on transmission owners and operators to be involved in every stage of planning, construction, and obligation. It asserts that the Proposed Rule was silent as to whether the proposed rules might work with respect to nonincumbent developers that are subsidized for the project but who then may not be interested or qualified to operate or own the facility, let alone comply with reliability standards. Indianapolis Power & Light also expresses concern that questions will remain regarding whether and to what extent a nonincumbent transmission developer is required to comply with NERC reliability standards. Other commenters respond that incumbent transmission owners and nonincumbent transmission

developers are subject to and have to meet the same reliability standards.[309]

**b. Commission Determination**

342. As discussed in section III.B.3 above, the Commission concludes that potentially increasing the number of asset owners through the elimination of a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, by itself, make it more difficult for system operators to maintain reliability. The Commission acknowledges, however, that a proposed transmission facility's impact on reliability is an important factor that is considered during evaluation of a proposed transmission facility for potential selection. We note that, when a nonincumbent transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it will be required to comply with all applicable reliability obligations, as every other registered entity is required. As part of that process, all entities, incumbent and nonincumbents alike, that are users, owners or operators of the electric bulk power system must register with NERC for performance of applicable reliability functions.

343. However, if there are still concerns regarding the lack of clarity as to when compliance with NERC registration and reliability standards would be triggered, we conclude that the appropriate forum to raise these questions and request clarification is

[309] *E.g.*, City of Santa Clara; Federal Trade Commission; NextEra; Northern California Power Agency; Pattern Transmission; and Western Independent Transmission Group.

the NERC process.

344. The Commission is sensitive to the concerns of some commenters that contend that existing transmission providers run the risk of violating NERC reliability standards in the event that a nonincumbent transmission developer abandons a transmission facility meant to address a violation. To address such concerns, the Commission clarifies that, if a violation of a NERC reliability standard would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project. Rather, the transmission provider must identify the specific NERC reliability standard(s) that will be violated and submit a NERC mitigation plan to address the violation. Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility .

### C. Interregional Transmission Coordination[310]

345. This section of the Final Rule adopts several reforms to improve coordination

[310] We note that our use of the term "coordination" with regard to the identification and evaluation of interregional transmission facilities is distinct from the type of coordination of system operations discussed in connection with section 202(a) of the FPA. *See supra* section III.A.2.

among public utility transmission planners with respect to the coordination of interregional transmission facilities. Specifically, the Commission requires each public utility transmission provider, through its regional transmission planning process, to enhance existing regional transmission planning processes in the following ways.[311] First, the Commission requires the development and implementation of procedures that provide for the sharing of information regarding the respective needs of neighboring transmission planning regions, as well as the identification and joint evaluation by the neighboring transmission planning regions of potential interregional transmission facilities that address those needs. Second, to ensure that developers of interregional transmission facilities have an opportunity for their transmission projects to be evaluated, the Commission requires the development and implementation of procedures for neighboring public utility transmission providers to identify and jointly evaluate transmission facilities that are proposed to be located in both regions. Third, to facilitate the joint evaluation of interregional transmission facilities, the Commission requires the exchange of planning data and information between neighboring transmission planning regions at least annually. Finally, to ensure transparency in the implementation of the

[311] In the Proposed Rule, the Commission sometimes referred to the requirements of this section as "interregional transmission planning"; however, we believe that "interregional transmission coordination" better describes what we are requiring in this Final Rule and, therefore, we will refer herein to "interregional transmission coordination."

foregoing requirements, the Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a website or e-mail list for the communication of information related to interregional transmission coordination.

346. Through these reforms, the Commission aims to facilitate the identification and evaluation of interregional transmission facilities that may resolve the individual needs of neighboring transmission planning regions more efficiently and cost-effectively. To accomplish these reforms, public utility transmission providers in each pair of transmission planning regions are directed to work through their regional transmission planning processes to develop the same language to be included in each public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the foregoing requirements. Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission planning agreement among the public utility transmission providers within neighboring transmission planning regions that is filed with the Commission.[312]

[312] We discuss the filing requirements for the same language to be included in each

(continued…)

### 1. Need for Interregional Transmission Coordination Reform[313]

#### a. Commission Proposal

347. In Order No. 890, the Commission found that, when transmission providers engage in regional transmission planning, they may identify solutions to regional needs that are more efficient than those that would have been identified if needs and potential solutions were evaluated only independently by each individual transmission provider.[314] In Order No. 890-A, the Commission reiterated that effective regional transmission planning must include coordination among transmission planning regions. To that end, the Commission required public utility transmission providers within each transmission planning region to coordinate as necessary to share data, information, and assumptions to maintain reliability and allow customers to consider resource options that span a

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public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements as well as for any interregional transmission coordination agreements in the compliance section below. *See* discussion *infra* section III.C.3.e. of this Final Rule.

[313] Legal authority issues associated with the interregional transmission coordination reforms described herein are addressed in the discussion above concerning regional transmission planning. *See* discussion *supra* section III.A.2. of this Final Rule.

[314] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

region.[315]

348. The Commission noted in the Proposed Rule that, within the Order No. 890 and 890-A framework, transmission providers in certain parts of the country have organized subregional transmission planning groups for the purpose of collectively developing transmission plans for facilities on their combined transmission systems. These subregional transmission plans are then analyzed at a regional level to ensure that, if implemented, they will be simultaneously feasible and meet reliability requirements. The Commission also acknowledged that some neighboring transmission planning regions have undertaken joint transmission planning pursuant to bilateral agreements.[316]

349. However, the October 2009 Notice observed that there are few processes in place to analyze whether alternative interregional solutions more efficiently or effectively would meet the needs identified in individual regional transmission plans. As part of the October 2009 Notice, the Commission posed several questions related to this issue, including whether existing transmission planning processes are adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers. The Commission also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.

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[315] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 226.

[316] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 103.

350. In light of the comments received on this issue, the Commission in the Proposed Rule expressed concern that the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential. The Commission noted that, in the few years since the issuance of Order No. 890, interest in multiregional transmission facilities has grown significantly.[317] Therefore, the Commission proposed reforms intended to improve coordination between neighboring transmission planning regions with respect to the evaluation of transmission facilities that are proposed to be located in both regions, as well as other possible interregional transmission facilities, to determine if such facilities address the needs of the transmission planning regions more efficiently or cost-effectively.[318]

**b. Comments**

351. Many commenters agree that there is a need to increase coordination in interregional transmission planning,[319] and identified a range of deficiencies in and

[317] The Commission cited two such recent multiregional projects. *Id.* n.46 (citing *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009); *Green Power Express LP*, 127 FERC ¶ 61,031 (2009)).

[318] *Id.* P 112-113.

[319] *E.g.*, AEP; Allegheny Energy Companies; AWEA; CapX2020 Utilities; Clean Line; Duke; East Texas Cooperatives; Edison Electric Institute; Energy Future Coalition;

(continued…)

opportunities for enhancement of existing interregional transmission coordination efforts. Several commenters state that a more defined and coordinated interregional transmission planning process is necessary. For example, AEP, joined by Integrys, contends that utility and regional transmission planning efforts have a limited geographic perspective and do not consider the benefits associated with interregional transmission projects in neighboring regions. Boundless Energy and Sea Breeze state that in the absence of RTOs and ISOs, and particularly in WECC, interregional transmission planning is ineffective, overly costly, and focuses on individual transmission projects with no relationship to the grid as a whole network or a smart grid.

352. Other commenters argue that there is no coordinated process between regions with respect to evaluating interregional transmission projects.[320] AEP and MidAmerican

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Environmental Defense Fund; Exelon; Federal Trade Commission; First Energy Service Company; Integrys; ISO New England; ITC Companies; Kansas City Power & Light and KCP&L Greater Missouri; LS Power; Massachusetts Departments; MidAmerican; MISO; MISO Transmission Owners; Minnesota PUC and Minnesota Office of Energy Security; National Grid; Natural Resources Defense Council; NEPOOL; New York ISO; NextEra; Northeast Utilities; Old Dominion; Organization of MISO States; Pattern Transmission; Pennsylvania PUC; PHI Companies; Pioneer Transmission; Powerex; PSEG Companies; PUC of Nevada; San Diego Gas & Electric; Sonoran Institute; Sunflower and Mid-Kansas; Transmission Access Policy Study Group; Vermont Electric; Westar; Wilderness Society and Western Resource Advocates; WIRES; and Wisconsin Electric Power Company.

[320] *E.g.*, East Texas Cooperatives; AEP; Kansas City Power & Light and KCP&L Greater Missouri; Anbaric and PowerBridge; Edison Electric Institute; MISO Transmission Owners; TDU Systems; AWEA; and PSEG Companies.

specify that the lack of a coordinated process between transmission planning regions creates hurdles for projects (especially proposed extra high voltage facilities) that are unreasonably higher than those faced by intraregional transmission projects. MidAmerican contends that different regions have different planning protocols and rules for project evaluation and justification, and focus too narrowly on planning criteria that are limited to reliability, generator interconnection, and economic congestion relief to demonstrate the need for a project. It states that many transmission planning regions do not have joint planning protocols or other tariff authority under which an interregional project could be approved based on the total benefits that it provides to the planning regions; and that there is a lack of coordinated planning to identify the most economically efficient solutions. Transmission Dependent Utility Systems state that the ultimate objective of the Final Rule should be the development of a regional transmission plan that jointly optimizes solutions for transmission across the regions to allow access to economically-priced energy by all transmission providers and customers to best serve their native loads. 26 Public Interest Organizations state that without interregional coordination of planning assumptions and procedures, it may not be possible to develop regional transmission plans that the Commission can rely on to determine whether rates are just and reasonable.

353. Some other commenters state that improved interregional transmission

coordination would result in a more orderly and timely transmission planning process.[321] Pioneer Transmission indicates that improved interregional transmission planning would require planning regions to adopt broader planning goals and objectives, plan transmission and generation in a coordinated and cohesive fashion, and recognize that the benefits of interregional transmission projects will multiply and that their beneficiaries often expand over time.

354. Several commenters also discuss the positive impacts that the proposed interregional transmission planning requirements would have on renewable resources. For example, some state that these requirements would facilitate access to renewable energy and help meet state, federal and other renewable energy goals.[322] Pattern Transmission indicates that unless a formal interregional planning process is required, approval of transmission projects needed to allow load to access renewable resources will be difficult, particularly for remotely-located resources. Wind Coalition states that without interregional planning, location-constrained resources located in one region that could be cost-effectively accessed to serve the needs of an adjacent, or even more distant region, will not be available or may be accessed through a more expensive and less efficient transmission solution than would be possible with interregional transmission

[321] *E.g.*, First Wind; Solar Energy Industries; and Large-scale Solar.

[322] *E.g.*, Edison Electric Institute; AWEA; Clean Line; American Transmission; and Solar Energy Industries and Large-scale Solar.

planning.

355. Some commenters argue that seams issues have prevented efficient use of existing transmission infrastructure and adequate consideration of the needs of load-serving entities at the seams.[323] Several commenters cite difficulties they have had in the MISO and PJM, Entergy and SPP, PJM and New York ISO, and Pacific Northwest regions.[324] For example, East Texas Cooperatives state a lack of coordination between SPP and Entergy has hindered its ability to obtain network service for a new generating plant. Specifically, East Texas Cooperatives state that in 2009 they submitted a request to SPP for 335 MW of network service sourcing and sinking in SPP to access the Harrison County generating plant. When studying the request, SPP determined that it may cause impacts on Entergy's system. After multiple iterations of the SPP Aggregate Study Process and two Affected System Analysis were conducted, the Entergy system identified $30.7 million of upgrades necessary to facilitate the request, the cost of which were to be directly assigned to East Texas Cooperatives. East Texas Cooperatives identified several potential issues in the SPP and Entergy studies that appeared to stem, at least in part,

[323] *E.g.*, AEP; Anbaric and PowerBridge; Connecticut & Rhode Island Commissions; East Texas Cooperatives; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; Northeast Utilities; and Omaha Public Power District.

[324] *E.g.*, Pennsylvania PUC; MidAmerican; Exelon; East Texas Cooperatives; PSEG Companies; and Powerex.

from a lack of queue coordination between Entergy and SPP. East Texas Cooperatives state that after significant effort on their part and additional study costs being incurred, which may not have been necessary with better coordination between Entergy and SPP, the cost of the necessary upgrades on the Entergy system was dramatically reduced. However, East Texas Cooperatives state that errors in SPP's planning studies and a lack of coordination between SPP and Entergy in addressing East Texas Cooperatives' network service request, resulted in a long delay in securing the necessary financing for the Harrison County project.

356. Similarly, ITC Companies state that it has been difficult to move forward on its Green Power Express project because there is no applicable planning process for projects that extend beyond the boundaries of a single RTO. Exelon states that its experience on the seam between MISO and PJM supports the contention that mandatory interregional planning is needed at this time. For instance, Exelon cites issues in studying and building transmission projects identified in the MISO's Regional Generation Outlet Study as necessary to deliver 35 GW of wind energy to load centers in the MISO. Exelon states that several of the projects are located in PJM, but will not be studied further by the MISO because MISO states that it has no authority to order its members or PJM members to build transmission on PJM's system. In addition, Exelon states that current coordination protocols between the MISO and PJM are failing to prevent increased congestion in PJM, resulting in deteriorating operations at the seam such as increased

transmission loading relief (TLR) events on the Commonwealth Edison system. PJM, however, disputes Exelon's assertions regarding both the cause and the total number of TLR events on the Commonwealth Edison system.

357. PSEG Companies recommend that where there is evidence of significant seams issues that affect operations, the Commission should require that the affected planning regions: (1) coordinate the planning of their systems, including sharing information needed to forecast, measure, and monitor impacts; and (2) form an agreement to address how the costs associated with cross-border impacts will be allocated that incorporates the "beneficiary pays" approach. Pennsylvania PUC states that the Commission's proposed interregional transmission planning requirements may help to improve interregional operational efficiency between RTOs.

358. Organization of MISO States and Pattern Transmission discuss the effect of improved interregional coordination between RTO and non-RTO regions. Organization of MISO States notes that the proposed requirements would enhance the incorporation of non-RTO regions into interregional transmission planning processes. According to Pattern Transmission, interregional transmission planning is particularly important in non-RTO and non-ISO regions, where the lack of a structured regional transmission planning process effectively restricts transmission development by nonincumbent developers to merchant transmission developers.

359. Transmission Dependent Utility Systems urge the Commission to adopt the

proposed interregional transmission planning reforms without delay as they are necessary to promote cost-effective interregional transmission planning and to remedy the unduly discriminatory exclusion of transmission customers that are load-serving entities from these activities. They assert that transmission providers have little incentive to develop transmission that would allow competing suppliers to serve customers and that in many regions, interregional transmission planning efforts are either nonexistent or are often implemented through bilateral agreements that provide no opportunity for active participation by transmission customers that are load-serving entities or other stakeholders.

360. Several commenters stress that the Commission's actions in this proceeding must not interfere with the ARRA-funded transmission planning initiatives.[325] Allegheny Energy Companies believe in the potential success of the ARRA-funded process. They state that the ARRA-funded interconnectionwide transmission planning initiatives may develop into a potential model for an open, interconnectionwide transmission planning process and in effect could help resolve some of the planning issues currently being encountered. Western Area Power Administration urges the Commission to consider the positive developments associated with the implementation of these initiatives while developing any Final Rule.

[325] *E.g.*, Indianapolis Power & Light; NARUC; PHI Companies; Pennsylvania PUC; PSC of Wisconsin; SPP; and Transmission Access Policy Study Group.

361. Some commenters argue that interregional transmission planning reforms are needed notwithstanding the ARRA-funded interconnectionwide transmission planning initiatives.[326] SPP states that the ARRA-funded process will not ensure that the most cost-effective solutions are implemented across planning regions or the entire interconnection. Transmission Dependent Utility Systems also contend that the ARRA-funded process does not address short-range needs for interregional projects and may have too wide of a geographic scope to conduct the bottom-up planning necessary to ensure that the needs of load-serving entities are met. AEP encourages the Commission to provide as much direction as possible to the planning authorities to ensure that the ARRA initiatives accomplish more than the cumulative assembly of the isolated plans of each region and planning entity.

362. Conversely, other commenters suggest that the Commission postpone imposing new requirements until after the ARRA-funded interconnection-wide transmission planning process is complete.[327] For example, Southwest Area Transmission Sub-Regional Planning Group encourages the Commission to support existing planning activities, postponing the proposal for additional requirements until after the ARRA-

[326] *E.g.*, SPP; Minnesota PUC and Minnesota Office of Energy Security; AEP; and Transmission Dependent Utility Systems.

[327] *E.g.*, Southwest Area Transmission Sub-Regional Planning Group; APPA; and Xcel.

funded interconnectionwide transmission planning initiatives are complete. ColumbiaGrid and ISO New England argue that their transmission planning processes already comply with the Commission's proposed requirements. The New England Transmission Owners support the Commission's interregional transmission planning objectives, but urge the Commission to give the ISO New England's existing interregional transmission planning process time to mature before imposing any new or additional requirements. PHI Companies argue that the Commission should require that existing interregional planning processes that meet the Commission's articulated principles be followed whenever the objectives of one region have the potential to impose burdens or costs on another region.

363. Other commenters oppose the Commission's proposed interregional transmission planning requirements, arguing they are unnecessary[328] or premature.[329] In particular, several commenters state that existing transmission planning processes in their regions (West, Southeast, Midwest) have led to significant progress and that there is no need for mandating that regions create interregional transmission planning agreements.[330] For

[328] *E.g.*, California ISO; ColumbiaGrid; Indianapolis Power & Light; National Rural Electric Coops; Southern Companies; and Washington Utilities and Transportation Commission.

[329] *E.g.*, Georgia Transmission Corporation; Salt River Project; and Southwest Area Transmission Sub-Regional Planning Group.

[330] *E.g.*, Salt River Project; Southwest Area Transmission Sub-Regional Planning

(continued…)

example, Southern Companies state that there already is an institution in place to provide interregional coordination in the Eastern Interconnection, namely the Eastern Interconnection Planning Collaborative. Salt River Project similarly states that it participates in robust and effective planning activities in the West, and provides an inventory of projects, including interregional lines that are being built as a result of coordination between regional and subregional planning groups. Southern Companies note that the Commission's proposed interregional transmission planning requirements are unnecessary as the deficiencies alleged by the Commission in the Proposed Rule are not applicable in the Southeast. Organization of MISO States expresses its view that the Commission should give the interconnectionwide Eastern Interconnection States Planning Council planning process some time to work before requiring the filing of any bi-regional interregional transmission planning agreements.

364. Salt River Project and Southwest Area Transmission contend that the proposed requirements are premature because the Commission did not provide specific examples of deficiencies and lack of coordination in the transmission planning process that support the need for the proposed requirements. They recommend that the Commission undertake a comprehensive and thorough inventory of existing planning processes and

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Group; Xcel; California Commissions; San Diego Gas & Electric; NEPOOL; Northeast Utilities; New England Transmission Owners; Southern Companies; Washington Utilities and Transportation Commission; and Indianapolis Power & Light.

then use the demonstrable outcomes of these processes to identify any real barriers that would merit new rules or regulations. National Rural Electric Coops, Indianapolis Power and Light, and Transmission Agency of Northern California contend, in whole or part, that the Commission should pursue only additional reforms that address specific problems identified in the record from this proceeding, that mandatory coordination should occur on an as-needed basis where such efforts are likely to lead to substantial transmission development, and that any further reforms be targeted to specific problems.

365. Some commenters suggest that the Commission should allow Order No. 890 processes to develop further before imposing new interregional coordination requirements.[331] Xcel acknowledges the need for interregional planning and cost allocation mechanisms to support public policy mandates, but recommends that the Commission allow current voluntary interregional planning and cost allocation discussions to continue, rather than mandate the development of interregional agreements within a specified time frame.

366. Similarly, several commenters contend that interregional coordination should be

[331] *E.g.*, Washington Utilities and Transportation Commission; Georgia Transmission Corporation; and Xcel.

voluntary. Ad Hoc Coalition of Southeastern Utilities and Bonneville Power contend that the Commission should permit parties to pursue voluntary interregional transmission planning agreements. Ad Hoc Coalition of Southeastern Utilities states that it supports voluntary efforts of regional transmission processes to address facilities located in multiple regions. Similarly, North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should be voluntary. Bonneville Power states that the Commission has not demonstrated that the voluntary approach does not work in the Pacific Northwest or that it is not just and reasonable or that it is unduly discriminatory or preferential. It recommends that if the Commission mandates interregional transmission planning agreements, it should permit parties the discretion to pursue voluntary agreements for interregional planning in general, as well as for specific projects. Further, California ISO points to successful voluntary coordination efforts in the West by WECC and California Transmission Planning Group. California PUC, in its reply comments, supports California ISO's and Bonneville Power's views.

367. Other reply commenters disagree with these arguments. 26 Public Interest Organizations respond that the Commission is obligated under the FPA to ensure that changing system needs (such as state renewable portfolio standards and new federal environmental rules) and the consequences for systems outside of the RTO's footprint (such as loop flow) are justly and reasonably addressed, which requires interregional coordination. WIRES replies that interregional planning must be made mandatory and

subject to stronger Commission oversight and participation. WIRES states that experience demonstrates that, left to the voluntary cooperation of the parties, the transmission network will not be integrated as effectively as it could be, reliability and resource diversity will suffer, and seams and congestion issues will be unresolved.

### c. Commission Determination

368. The Commission concludes that implementation of further reforms in the area of interregional transmission coordination activities are necessary at this time. As the Commission stated in the Proposed Rule, in the absence of coordination between transmission planning regions, public utility transmission providers may be unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes, potentially including interregional transmission facilities. Clear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans.

369. Specifically, we agree with commenters, such as AEP, that the transmission planning requirements of Order No. 890 are too narrowly focused geographically and fail to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions. Our decision also is influenced

by those commenters that cite seams issues or difficulties they have encountered in coordinating the development of transmission facilities across the regions, including between RTOs and ISOs, as well as between an RTO or ISO and non-RTO or ISO region and among non-RTO regions. We are persuaded by those commenters who argue that additional interregional transmission coordination requirements would facilitate consideration of transmission needs driven by Public Policy Requirements by enabling the evaluation of interregional transmission facilities that may address those needs more efficiently or cost-effectively. We agree with Transmission Dependent Utility Systems' comments that interregional transmission coordination promotes cost-effective transmission development and facilitates transmission customer participation in interregional transmission coordination efforts.

370. Given the clear need for reform of existing interregional transmission coordination practices, we are not persuaded by arguments contending that reform is not necessary or is premature. While we recognize that significant progress with respect to the development of open and transparent transmission planning processes has been made around the country, the existing transmission planning processes nevertheless do not adequately provide for the evaluation of proposed interregional transmission facilities or the identification of interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities.

Because such interregional transmission coordination helps to ensure that rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential by facilitating more efficient or cost-effective transmission infrastructure development, we conclude that the interregional transmission coordination reforms adopted in this Final Rule are necessary and should not be delayed.

371. Similarly, while we have considered the positive developments associated with the ARRA-funded transmission planning initiatives, we nevertheless agree with commenters who argue that the Commission should not postpone its proposed interregional transmission coordination reforms on account of these initiatives. While the ARRA-funded transmission planning initiatives represent a significant advancement in interconnectionwide transmission scenario analysis, they do not specifically provide for the ongoing coordination in the evaluation of interregional transmission facilities, which we conclude is necessary to ensure that rates, terms, and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential. As requested by commenters, however, we have extended the compliance deadline for the interregional coordination requirements of this Final Rule, as discussed in section V.A below. We encourage public utility transmission providers to continue their participation in these efforts and to explore opportunities to use the valuable information these efforts provide in their regional transmission planning and interregional transmission coordination efforts. We reiterate our intent to build upon, and not interfere with, the

ARRA-funded transmission planning initiatives in this Final Rule.

372. With regard to commenters' contentions that their existing interregional transmission coordination efforts already comply with the Proposed Rule's provisions or need more time to mature, we acknowledge that some transmission planning regions already may engage in interregional transmission coordination efforts that satisfy some of the requirements discussed below or are developing such efforts. The Commission is acting in this Final Rule to establish a minimum set of requirements that apply to all public utility transmission providers. If a public utility transmission provider believes that it participates in a regional transmission planning process that fulfills the interregional transmission coordination requirements adopted in this Final Rule, it may describe in its compliance filing how such participation complies with the requirements of this Final Rule.

373. We therefore disagree that the Commission should undertake additional investigation of the need for interregional coordination procedures or require them only on a case-by-case basis. The record in this proceeding is adequate to support our conclusion that the existing requirements of Order No. 890 are too narrowly focused geographically. Coordination of transmission planning activities by neighboring transmission planning regions will increase opportunities to identify interregional transmission facilities that address the needs of those regions more efficiently or cost-effectively. We thus see no need to adopt a case-by-case approach to our requirements.

We conclude that the interregional coordination obligations implemented in this Final Rule are necessary to establish a minimum set of requirements that are applicable to all public utility transmission providers.

### 2. Interregional Transmission Coordination Requirements

#### a. Interregional Transmission Coordination Procedures

##### i. Commission Proposal

374. In the Proposed Rule, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to enter into agreements that include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed that could address transmission needs more efficiently than separate intraregional facilities.[332] While acknowledging that every transmission planning agreement could be tailored to best fit the needs of the transmission planning regions entering into the agreement, the Commission proposed that each public utility transmission provider ensure that certain elements are included in each

[332] The Commission discusses in subsection 3e below comments in response to the proposal for interregional transmission coordination activities to be memorialized in an agreement executed by multiple public utility transmission providers.

agreement.

375. Specifically, the Commission proposed that an interregional transmission planning agreement must include the following elements: (1) a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities (Coordination); (2) an agreement to exchange at least annually planning data and information (Data Exchange); (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions (Joint Evaluation); and (4) a commitment to maintain a website or e-mail list for the communication of information related to the coordinated transmission planning process (Transparency).

376. With respect to the third proposed element, the Commission proposed that the transmission developer of a transmission project that would be located in two neighboring transmission planning regions must first propose its transmission project in the transmission planning process of each of those transmission planning regions. The Commission further proposed that such a submission would trigger a procedure established by the interregional transmission planning agreement, under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed transmission project. The Commission proposed that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than

subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, the Commission proposed that inclusion of the interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an interregional cost allocation method that satisfies the cost allocation principles set forth in the Proposed Rule.

**ii. Comments**

377. American Transmission supports requiring regions to make a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently than separate intraregional facilities. However, American Transmission also recommends that the Commission require public utility transmission providers to specifically describe the process by which their planning regions will identify such interregional transmission facilities. East Texas Cooperatives suggest that the Commission clarify that it requires more than simple coordination (i.e., the sharing of information and plans), but also the establishment of an interregional transmission planning process intended to address and resolve seams issues.

378. Several commenters request that the Commission provide more detailed guidance

on the interregional transmission planning agreements.[333] MISO Transmission Owners similarly request that the Commission clarify its specific expectations for interregional coordination. SPP recommends that the Final Rule provide detailed guidance concerning the requirements for interregional transmission planning, including the goals and objectives of interregional transmission planning. Powerex states that the Commission should require each interregional transmission planning agreement to include a set of interregional planning goals that are concrete and outcome-based and that directly address the reliability problems that reduce efficiency. ITC Companies state that interregional transmission planning agreements should include the key criteria to be considered in the interregional planning process, based on the planning principles, and the cost allocation method that would apply to approved interregional projects.[334]

379. Old Dominion recommends that the Commission require public utility transmission providers and interregional planning entities, such as the Eastern Interconnection Planning Collaborative, to adopt transmission planning processes that: (1) identify the needs of multiple transmission systems based on scenario planning using a long-term planning horizon (e.g., 15 to 20 years); (2) conduct various scenario analyses

[333] *E.g.*, 26 Public Interest Organizations; MISO Transmission Owners; SPP; and Sunflower and Mid-Kansas.

[334] The cost allocation method that would apply to selected interregional transmission facilities is addressed in the cost allocation section below. *See* discussion *supra* section IV.E. of this Final Rule.

to identify the projects that best address reliability, economic, or demand response concerns; and (3) allow developers to compete to provide the "best" solution.

380. Some commenters support a more robust interregional transmission planning process than the interregional coordination requirements set forth in the Proposed Rule. For example, Energy Future Coalition states the interregional transmission planning process should include a rigorous and transparent analysis of a comprehensive set of considerations and alternatives and provide for "right-sizing" facilities to ensure the best possible use of existing corridors and minimize environmental impacts from new corridors.

381. A few commenters recommend that the Commission require interregional transmission planning processes to comply with the Order No. 890 planning principles.[335] Transmission Dependent Utility Systems contend that subjecting interregional transmission planning processes to the Order No. 890 planning principles would alleviate concerns about the limited size of some Order No. 890-compliant planning regions, which arose due to the lack of an opportunity for load-serving entities to participate in planning across seams, and would ensure that the most cost-effective solutions to constraints associated with seams are pursued. Old Dominion states that requiring interregional transmission planning processes to comply with the Order No. 890 planning

[335] *E.g.*, East Texas Cooperatives; ITC Companies; Old Dominion; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

principles would ensure that information will flow between the regional and interregional transmission planning processes, so that stakeholders will have the information necessary to offer meaningful input at the interregional level and to inform discussions at the regional levels.

382. Energy Consulting Group states that transmission owners should be required to develop the transmission upgrades and expansions identified in the wide-area planning process within a mandated time frame. NextEra states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes interregional transmission facilities identified through the planning process. Boundless Energy and Sea Breeze contend that the Commission should strengthen interregional transmission planning processes by requiring implementation of interregional transmission plans and an implementing authority. MidAmerican expresses concern that proposed element 1 does not describe how the Commission intends neighboring planning regions to move those interregional projects identified towards construction, and recommends that the Commission require the identified interregional facilities to be included in local and regional transmission plans. Similarly, National Grid recommends that the Commission require consideration of procedures for adopting into regional plans any transmission upgrade identified as part of an interregional coordination process.

383. Southwest Area Transmission Sub-Regional Planning Group, however, states that

the Commission should clarify that interconnectionwide, regional, and interregional planning groups are not decision-making entities with the authority to direct developers or load-serving entities to develop any project. National Grid asks the Commission not to require the formation of new interregional planning entities, especially where interregional planning efforts are already underway.

384. NextEra also states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes longer-term objectives that have not yet resulted in proposals for specific facilities. Similarly, California Commissions state that plans should contain conceptual elements that have yet to materialize as specific transmission projects and contingent elements that may be needed under certain future scenarios so that a plan can evolve over time.

385. Solar Energy Industries and Large-scale Solar and Anbaric and PowerBridge urge the Commission to impose stronger requirements for interregional coordination for public policy and renewable energy projects. MidAmerican asks that the Commission clarify that consideration of public policy requirements is not limited to local and regional transmission planning processes but should be extended to interregional transmission coordination as well.

386. On the other hand, Energy Consulting Group contends that interregional transmission planning should provide an incentive for development of transmission facilities that provide access to economic generation resources that minimize power costs,

not act as an instrument of public policy. Energy Consulting Group also states that it is not clear that the proposed transmission planning processes will have a mechanism to address transmission service requests, and that a process for addressing such requests should be added to wide-area planning.

387. ITC Companies contend that interregional coordination should assure equal consideration for all drivers of transmission needs, including reliability, generator interconnection, and public policy requirements. National Grid requests that the Commission require interregional transmission planning efforts to consider transmission upgrades that could provide economic benefits to consumers in multiple regions and upgrades or modified operating practices that could result in more efficient use of the existing transmission system in addition to those transmission facilities needed to maintain reliability. Powerex states that the Final Rule should establish policies that encourage transmission customers to continue to purchase and invest in long-term transmission and that the Commission should ensure that it is sending proper signals for long-term investments in transmission by rejecting policies that erode the existing rights of firm transmission customers that have already made long-term investments in transmission service.

388. Organization of MISO States urges the Commission to encourage transmission planning regions to coordinate on issues besides transmission planning and cost allocation, such as interconnection and operational issues.

389. North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should complement, rather than substitute for, local and narrower regional planning processes. NEPOOL and Northeast Utilities state that the Proposed Rule's provisions, which reflect a "bottom up" planning approach, should be reflected in any Final Rule. Other commenters also support a "bottom up" approach to interregional transmission planning.[336]

390. Other commenters urge the Commission to ensure that the Final Rule does not infringe on state authority. California Commissions emphasize that rules pertaining to interregional transmission planning agreements and the resulting coordinated planning process must not diminish state control by shifting decision-making to the Commission and that states should be directly involved in the development of interregional transmission planning agreements and should have a strong role in their implementation. NARUC asserts that the interregional transmission planning process must continue to respect the role of state commissions in reviewing and guiding the planning process and the role of state authorities in ultimately siting any transmission lines.

391. Several commenters request that the Commission oversee the development and implementation of interregional transmission planning agreements and/or monitor the

[336] *E.g.*, Allegheny Energy Companies; East Texas Cooperatives; and ISO New England.

progress of interregional planning efforts.[337] For example, Organization of MISO States suggests that the Commission require an accountability and oversight element in interregional transmission planning agreements to ensure that such agreements are implemented as intended, perhaps utilizing the expertise of state commissions. American Transmission and MISO Transmission Owners state that public utility transmission providers and their stakeholders should be required to conduct periodic reviews of the effectiveness of their interregional transmission planning efforts and file informational reports with the Commission.

392. Federal Trade Commission acknowledges that the Commission's proposed interregional transmission planning requirements would require market participants that may be competitors to collaborate with each other in transmission planning, construction, ownership, and operation, but states that participants in the interregional transmission planning process should not view the antitrust laws as an impediment to their participation.

### iii. Commission Determination

393. To remedy the potential for unjust and unreasonable rates for public utility transmission providers' customers, we adopt the interregional transmission coordination requirements discussed below. These interregional transmission coordination

[337] *E.g.*, Energy Future Coalition; Organization of MISO States; Transmission Dependent Utility Systems; and AWEA.

requirements obligate public utility transmission providers to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs identified in their respective local and regional transmission planning processes.

394. In the Proposed Rule, the Commission set forth its proposed interregional transmission coordination requirements in the form of four elements to be included in an interregional transmission planning agreement. After reviewing the comments concerning interregional transmission coordination received in this proceeding, we find that these four elements are so extensively interconnected that it would be inappropriate to require that they be addressed as distinct elements, as was proposed in the Proposed Rule. Instead, we believe that these four elements are better represented as characteristics of interregional transmission coordination. Specifically, two of the proposed elements—Coordination and Joint Evaluation—embody the purpose of interregional transmission coordination: to coordinate and share the results of regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities and to jointly evaluate such facilities, as well as to jointly evaluate those transmission facilities that are proposed to be located in more than one transmission planning region. The other two elements—Data Exchange and Transparency—are more appropriately described as part of the procedures through which effective interregional

transmission coordination is implemented.

395. Thus, the framework in which we present these requirements differs from that of the Proposed Rule. This Final Rule lays out the objectives of interregional transmission coordination followed by a discussion of the mechanics of interregional transmission coordination instead of four required elements. Here we address the requirements for interregional transmission coordination, the entities between which interregional transmission coordination must occur, and the transmission facilities to which the interregional transmission coordination requirements apply. Hence the discussion of Coordination and Joint Evaluation is here. We address in other sections below the mechanics of implementation, including a discussion of the procedures for joint evaluation, requirements for data exchange, transparency, stakeholder participation, and the required revisions to the OATT.

396. The Commission requires each public utility transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Through adoption of this requirement, the Commission intends that neighboring transmission planning regions will enhance their existing regional transmission planning processes to provide for: (1) the

sharing of information regarding the respective needs of each region, and potential solutions to those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs.[338] By requiring public utility transmission providers to undertake such interregional transmission coordination activities, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are more efficient or cost-effective solutions to meeting transmission planning region's needs.

397. In response to the Proposed Rule, several commenters seek clarification from the Commission as to whether, for example, the Commission intends the formation of a new interregional transmission planning process or that certain types of facilities or objectives should be the focus of interregional transmission coordination. With the exception of the requirements for implementing interregional transmission coordination discussed herein, the Commission declines at this time to impose specific obligations as to how neighboring transmission planning regions must share information regarding their needs, and potential solutions to those needs, or identify and jointly evaluate interregional

[338] The same language must be included in each public utility transmission provider's OATT that describes the processes that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements of this Final Rule. The filing requirements concerning this same language are discussed in the compliance section below. *See* discussion *infra* section VI.A. of this Final Rule.

transmission alternatives to those regional needs, as well as proposed interregional transmission facilities. Thus, we also decline to require the use of specific planning horizons or the performance of particular scenario analyses. While we appreciate commenters' desire for additional clarity on this point, the Commission believes it is appropriate to leave to the transmission planning regions in the first instance adequate discretion to allow for the development and implementation of interregional transmission coordination procedures that suit the needs of the neighboring transmission planning regions. In light of the varying approaches to transmission planning that are currently used by transmission planning regions across the country, providing further guidance at this time could inadvertently impose restrictions that are not appropriate for a particular transmission planning region.

398. However, we clarify in response to East Texas Cooperatives that the interregional transmission coordination requirements adopted do require that public utility transmission providers do more than simply commit to share their regional transmission plans and other transmission planning information. To comply with the requirements in this Final Rule, each public utility transmission provider, through its regional transmission planning process, must develop and implement additional procedures that provide for the sharing of information regarding the respective needs of each neighboring transmission planning region, and potential solutions to those needs, as well as the identification and joint evaluation of interregional transmission alternatives to those

regional needs by the neighboring transmission planning regions. On compliance, public utility transmission providers must describe the methods by which they will identify and evaluate interregional transmission facilities. While the Commission does not require any particular type of studies to be conducted, this Final Rule requires public utility transmission providers in neighboring transmission planning regions to jointly identify and evaluate whether interregional transmission facilities are more efficient or cost-effective than regional transmission facilities. Accordingly, the Commission requires that the compliance filing by public utility transmission providers in neighboring planning regions include a description of the type of transmission studies that will be conducted to evaluate conditions on their neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities.

399. We decline to adopt the recommendations of those commenters that suggest that the Commission adopt a more robust, formalized interregional transmission planning process than the interregional transmission coordination requirements in the Proposed Rule, such as an interregional transmission coordination process that complies with the Order No. 890 transmission planning principles or that produces an interregional transmission plan. We clarify here that the interregional transmission coordination requirements that we adopt do not require formation of interregional transmission planning entities or creation of a distinct interregional transmission planning process to

produce an interregional transmission plan. Rather, our requirement is for public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs more efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions. To the extent that public utility transmission providers wish to participate in processes that lead to the development of interregional transmission plans, they may do so and, as relevant, rely on such processes to comply with the requirements of this Final Rule.

400. While we acknowledge MidAmerican's concern that the Commission does not specify how interregional transmission facilities will be moved toward construction, we note that in the Proposed Rule, the Commission stated that, consistent with Order No. 890, the proposed regional transmission planning obligations do not address or dictate which investments identified in a transmission plan should be undertaken by public utility transmission providers.[339] We affirm that statement, and further note that Order No. 890 already requires that public utility transmission providers make available information regarding the status of transmission upgrades identified in their regional transmission plans in addition to the underlying transmission plans and related transmission studies.[340]

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[339] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.59 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438).

[340] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

The Commission made clear in Order No. 890-A that transmission providers must make available to other stakeholders information regarding the progress and construction of transmission upgrades and transmission facilities.[341] To the extent neighboring transmission planning regions identify interregional transmission facilities of mutual benefit and have such transmission facilities in their individual regional transmission plans, these informational requirements will apply to the portions of the interregional transmission facilities within each of the individual region's transmission plans. We decline to require, as suggested by MidAmerican and National Grid, that every interregional transmission facility that is evaluated through the interregional transmission coordination procedures automatically be selected in a regional transmission plan for purposes of cost allocation. However, as discussed below, an interregional transmission facility must be selected in both of the relevant regional transmission plans for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to an interregional cost allocation method required under this Final Rule. Rather, we expect that information exchanged during the interregional coordination effort should inform discussions at the regional and local transmission planning level.

401. Moreover, in response to commenters, this Final Rule neither requires nor precludes longer-term interregional transmission planning, including the identification of

[341] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 202.

conceptual or contingent elements,[342] the consideration of transmission needs driven by Public Policy Requirements,[343] or the evaluation of economic considerations.[344] Whether and how to address these issues with regard to interregional transmission facilities is a matter for public utility transmission providers, through their regional transmission planning processes, to resolve in the development of compliance proposals. However, the Commission agrees with North Carolina Agencies that interregional transmission coordination should complement local and regional transmission planning processes, and should not substitute for these processes. Consistent with the implementation requirements for interregional transmission coordination procedures discussed in section III.C.3.a. below, we clarify that interregional transmission coordination may follow a "bottom up" approach. In response to Energy Consulting Group, we neither require nor prohibit consideration by neighboring transmission planning regions of requests for transmission service or upgrades within the interregional transmission coordination procedures required in this Final Rule.

402. With respect to commenters' assertion that this Final Rule should not infringe on state authority, we emphasize here that the interregional transmission coordination requirements are not intended to infringe on state authority. We acknowledge the vital

[342] *See* California Commission.

[343] *See* MidAmerican.

[344] *See* Energy Consulting Group.

role that state agencies play in transmission planning and their authority to site transmission facilities. We strongly encourage state agencies to be involved in the development and implementation of the interregional transmission coordination procedures necessary to satisfy the interregional transmission coordination requirements adopted herein.

403. In response to commenters' requests that we monitor the implementation of the interregional transmission coordination requirements adopted in this Final Rule and the progress of interregional transmission coordination efforts, although the Commission believes that Commission oversight of compliance with this Final Rule and assessment of the adequacy of its measures is appropriate, the Commission does not intend to monitor coordination efforts so closely as to intrude in the interregional transmission coordination activities. It is not necessary for the Commission to decide the exact level of its monitoring at this time.

404. We also decline to require public utility transmission providers and their stakeholders to conduct periodic reviews of the effectiveness of their interregional transmission coordination efforts and file information reports with us, as suggested by American Transmission and MISO Transmission Owners. However, we do encourage such reviews. We also note that parties may utilize the dispute resolution provisions of the relevant public utility transmission provider's OATT or file a complaint with the Commission if they find that the interregional transmission coordination procedures

described in a public utility transmission provider's OATT are not being implemented properly.

### b. Geographic Scope of Interregional Transmission Coordination

#### i. Commission Proposal

405. As noted above, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues. The Commission noted that this does not require a public utility transmission provider to coordinate with a neighboring transmission planning region in another interconnection. However, the Commission also encouraged public utility transmission providers to explore possible multilateral interregional transmission coordination processes among several, or even all, transmission planning regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives.[345] The Commission proposed to require interregional coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed but that could address

[345] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114-15.

transmission needs more efficiently than separate intraregional transmission facilities.[346]

**ii. Comments**

406. The Commission received a number of comments addressing the geographic scope of the proposed interregional coordination requirements, as well as the specific entities within the appropriate geographic scope that would be required to coordinate. Several commenters suggest that the Commission clarify how it defines regions for purposes of regional transmission planning to provide clarity as to how its proposed interregional transmission planning requirements will be implemented.[347] Transmission Dependent Utility Systems recommend that the Commission define regional boundaries if it appears that there is discrimination or inefficiencies in the planning process. Others urge the Commission not to change existing areas over which transmission planning is now coordinated among transmission planning regions.[348] For example, Integrys suggests that the Final Rule should preserve the existing mandate that PJM and the MISO constitute a single common market in the application of interregional transmission planning rules, and thus should be considered, at least for certain purposes, a single region subject to the interregional transmission planning and cost allocation rules.

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[346] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 116.

[347] *E.g.*, Integrys; Transmission Dependent Utility Systems; and MISO Transmission Owners.

[348] *E.g.*, Integrys and National Grid.

407. New York Transmission Owners agree with the Commission's proposal to require that interregional transmission planning agreements between neighboring planning regions address transmission facilities that are proposed to be located in both regions. However, New York ISO states that this requirement should not preclude planning regions from considering other types of projects.

408. Several commenters either agree with the Commission's encouragement to extend interregional planning voluntarily beyond coordination between neighboring transmission planning regions so as to cover larger areas or an interconnection, or ask the Commission to require planning over such larger areas. ITC Companies state that, because some projects may involve more than two transmission planning regions, interregional planning also may need to involve more than two transmission planning regions. WECC suggests that because it already serves as a facilitator for interconnectionwide transmission planning and coordination in the Western Interconnection, it could provide a forum for facilitating multilateral transmission planning agreements. Federal Trade Commission recommends that the Commission institutionalize interconnectionwide transmission planning to incorporate relevant congestion, reliability, and environmental considerations and to reflect the geographic scope of power flows.

409. AWEA recommends that the Commission require public utility transmission providers to enter into multilateral, or even interconnectionwide, interregional transmission planning agreements. Similarly, Wind Coalition encourages the

Commission to consider extending its proposed interregional transmission planning requirements beyond adjacent planning regions to provide a process for accessing location-constrained resources located in more distant regions. Grasslands contends that the Commission should not limit its proposed interregional coordination requirements to neighboring transmission planning regions within the same interconnection. Without interregional transmission planning between the interconnections, Grasslands claims that transmission developers will not develop transmission facilities that will efficiently link the interconnections in the future.

410. Organization of MISO States cautions that, even with implementation of the proposed interregional transmission planning requirements, it may be difficult to require any non-RTO or non-ISO public utility transmission provider to act in the best interests of a geographic footprint beyond its own. Thus, it states that efforts such as the Eastern Interconnection States Planning Council, which would view projects over a geographic region larger than the RTO footprint, may be valuable.

411. Other commenters support the Commission's intent not to mandate interconnectionwide transmission planning,[349] offering among other things that mandating interconnectionwide planning would increase the difficulty of resolving local issues by making coordinated planning among transmission planning regions more

[349] *E.g.*, Indianapolis Power & Light; Transmission Access Policy Study Group; MISO Transmission Owners; New York ISO; and Organization of MISO States.

complex and risk frustrating the ARRA-funded interconnectionwide transmission planning initiatives.

412. American Transmission and MISO Transmission Owners state that with respect to planning activities in regions without an RTO or ISO, the Commission should provide guidance as to which entities would be required to coordinate with each other. Integrys states that the Commission might implement its proposed interregional transmission planning requirements in non-RTO regions by requiring transmission providers in such regions to form planning consortia that could operate within a region and/or between two or more regions. Indianapolis Power & Light suggests that the Commission clarify whether transmission providers would be required to coordinate with each individual entity or one planning region to coordinate with another planning region.

413. New York ISO states that the Commission should clarify that public utility transmission providers that are unable to reach interregional transmission planning agreements with neighboring Canadian systems will not be deemed out of compliance with the Final Rule.

414. MISO Transmission Owners state that the agreements should enable a region impacted by a proposed project located in a neighboring region to review the neighboring region's plans, and that the transmission planning regions subject to the agreement should agree on what level of impact is material, as well as how disputes between the parties will be resolved. Edison Electric Institute and Exelon likewise state that the Commission

should require that interregional transmission planning agreements address transmission facilities located in a single region that could have significant adverse impacts on the reliability of neighboring regions. Moreover, Exelon states that interregional transmission planning agreements should require that if a proposed project would result in any reliability violations or increased congestion on a neighboring system, these impacts must be mitigated before the project is approved.

### iii. Commission Determination

415. We require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to implement the interregional transmission coordination requirements adopted in this Final Rule. This requirement is necessary to improve coordination of neighboring transmission planning regions' activities, facilitating the identification and joint evaluation of interregional transmission solutions that could meet local and regional transmission needs more efficiently or cost-effectively than separate regional transmission solutions alone.

416. The Commission declines to expand the interregional transmission coordination requirements adopted herein to require joint evaluation of the effects of a new transmission facility proposed to be located solely in a single transmission planning region. Although this Final Rule requires each regional transmission planning process to identify the consequences of a proposed new transmission facility in another transmission

planning region as we explain below in the discussion of Cost Allocation Principle 4,[350] we do not require that be done interregionally. To do so could have the effect of mandating interconnectionwide transmission planning, given that transmission facilities located within one transmission planning region often have effects on multiple neighboring systems, which could trigger a chain of multilateral evaluation processes. However, we believe that the exchange of planning data and information between neighboring transmission planning regions consistent with the interregional transmission coordination requirements of the Final Rule will assist transmission planners in understanding and managing the effects of a transmission facility located in one region upon another neighboring region. Further, although we decline to impose a joint evaluation by more than one region of a facility located solely in one transmission planning region, nothing in this Final Rule precludes public utility transmission providers from developing and proposing interregional processes for that purpose.[351]

417. While the Commission declines to require multilateral or interconnectionwide coordination in this Final Rule, we continue to encourage public utility transmission

[350] *See* discussion *infra* section IV.E.5. of this Final Rule.

[351] Moreover, the absence of such a requirement in this Final Rule does not affect any obligations public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including but not limited to any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice.

providers to explore the possibility of multilateral interregional transmission coordination among several, or even all, transmission planning regions within an interconnection, building on the processes developed through the ARRA-funded transmission planning initiatives. The Commission agrees that imposing multilateral or interconnectionwide coordination requirements at this time could frustrate the progress being made in the ARRA-funded transmission planning initiatives. To the extent that stakeholders in those planning initiatives wish to continue these activities at the conclusion of the ARRA-funded transmission planning initiatives, we encourage them to explore how existing regional transmission planning processes and interregional transmission coordination procedures implemented under Order No. 890 and this Final Rule could be enhanced to provide for such transmission planning activities.

418. We decline to adopt Grasslands' recommendation that the Commission require interregional transmission coordination between transmission planning regions located in different interconnections. While we recognize that interregional transmission coordination between transmission planning regions in different interconnections could provide transmission planning benefits, such as increased power flows between interconnections, it may provide greater benefits for some pairs of neighboring transmission planning regions than for others due to geographical and operational limitations. Therefore, while we encourage public utility transmission providers to consider coordinating with neighboring transmission planning regions in different

interconnections where it would be helpful, we do not find it appropriate to require such coordination in this Final Rule.

419. In response to American Transmission and MISO Transmission Owners' request for guidance regarding the entities that they are required to coordinate with in neighboring regions without an RTO or ISO, we reiterate that we require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection. Thus, interregional transmission coordination would occur between the public utility transmission providers in two neighboring transmission planning regions.

420. As discussed above in the regional transmission planning section,[352] the Commission declines to revisit how each transmission planning region defines itself, as requested by Integrys and Transmission Dependent Utility Systems. We also decline to adopt Integrys' suggestion that the Commission could implement its interregional transmission coordination requirements in non-RTO regions by requiring public utility transmission providers in such regions to form planning consortia. Public utility transmission providers are free to do so; however, we do not want to foreclose other approaches to meeting the interregional transmission coordination requirements in this

[352] *See supra* section III.A.3 of this Final Rule.

Final Rule.

421. We clarify for New York ISO that a public utility transmission provider will not be deemed out of compliance with this Final Rule if it attempts to and is unable to develop interregional transmission coordination procedures with neighboring transmission systems in another country.

### 3. Implementation of the Interregional Transmission Coordination Requirements

#### a. Procedure for Joint Evaluation

##### i. Comments

422. Several commenters express support for the Commission's proposal to require the development of a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in neighboring transmission planning regions.[353] Some commenters seek clarification of this requirement. For example, Duke suggests that the Commission clarify whether it intends that only one joint interregional study will be performed for a proposed interregional project, regardless of the number of regions that are crossed, as multiple studies would result in an inefficient use of resources. ISO/RTO Council and PJM ask whether the Commission intends "joint evaluation" to mean coordination of stakeholder meetings and processes and/or the creation of a new set of

[353] *E.g.*, American Transmission; New York Transmission Owners; Northeast Utilities; and Transmission Dependent Utility Systems.

planning criteria and a new planning cycle. In addition, PJM requests clarification as to whether the Commission intends "joint evaluation" to be conducted consistent with an interregional agreement such as the PJM/MISO Joint Operating Agreement.

423. Several commenters urge the Commission to provide flexibility in developing and implementing planning agreements.[354] They state that although the Commission proposed to require that interregional transmission planning agreements include the four elements of interregional coordination, the Commission also encouraged every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement. ISO New England urges the Commission to allow flexibility for regions to define in their interregional transmission planning agreements what it means to "jointly evaluate" interregional projects.

424. In setting out the details of interregional coordination, PUC of Nevada urges the Commission to consider the ongoing efforts in the Western Interconnection to address interregional coordination. WestConnect Planning Parties state that any requirement to execute an interregional transmission planning agreement should respect the various organizational structures of existing regional and interregional planning processes, as well as allow signature by all formal participants in the interregional planning process instead of requiring "formation of a legal entity authorized to act on behalf of those

[354] *E.g.*, PUC of Nevada; New York ISO; and Dayton Power and Light.

participants."

425. Other commenters offer specific suggestions as to the design and implementation of interregional coordination procedures. Minnesota PUC and Minnesota Office of Energy Security argue that, for the studies of an entire project to be meaningful and informative, all transmission planning entities studying a project should be required to coordinate their information and studies. Pioneer Transmission recommends that the Commission require planning regions to evaluate interregional projects through a single, coordinated process. It believes that if projects are studied under separate procedures by each planning region, interregional coordination would be unnecessarily delayed and more expensive than if the project was studied under a single set of procedures. However, Connecticut & Rhode Island Commissions contend that the Commission should require that proposed interregional projects be independently processed through each applicable regional planning process before they are eligible for joint evaluation through interregional coordination procedures.

426. Old Dominion similarly recommends that coordinated analysis of interregional transmission facilities be accomplished through preliminary evaluation within existing regional transmission planning processes, followed by an evaluation of the project on an interregional basis. If the identified transmission facility is determined to meet interregional needs, the relevant transmission planning regions would incorporate the project into their regional transmission planning processes and further assess its effects

on regional needs. Old Dominion recommends that the Commission require this "feedback loop" so that local and regional transmission plans can be reconsidered once an interregional transmission plan has been developed. Similarly, New England States Committee on Electricity supports the Commission's proposed interregional coordination requirements provided that interregional projects will be identified and developed through the current approach that begins with and respects the regional transmission planning process and resulting regional transmission plan.

427. Several commenters suggest that the Commission should develop a *pro forma* interregional transmission planning agreement. NextEra suggests that such an agreement include the steps by which the regions and their stakeholders will identify the transmission facilities necessary to meet their needs. Otherwise, NextEra contends that the negotiation of such agreements is likely to be cumbersome. ITC Companies agrees that development of a *pro forma* interregional planning agreement would provide clarity regarding the Commission's minimum requirements and, if designed properly, could avoid replication of flaws in existing transmission planning processes that occurred in the PJM and MISO Joint Operating Agreement. In its reply comments, PJM agrees with ITC Companies that a more standardized planning process that includes a *pro forma* interregional planning agreement could improve coordination with respect to interregional facilities, and cautions that the Commission cannot simply recite regional differences as the basis for not establishing broader criteria. However, PJM contends that

ITC Companies' argument regarding the Joint Operating Agreement is likely premised on the fact that their project was not selected in the RTOs' respective regional transmission plans. In its reply, Southern California Edison argues that adopting a *pro forma* agreement is not workable because planning coordination differs significantly at each RTO/ISO and among vertically integrated utilities.

428. Pennsylvania PUC suggests that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission regions negotiating bilateral coordination agreements. Pennsylvania PUC warns, however, that the joint operating agreement between PJM and MISO may require improvement in both content and operation with regard to interregional transmission planning and construction.

429. PJM requests that, before requiring greater interregional coordination, the Commission clarify whether it will continue to allow regional differences in transmission planning processes or it intends to require greater standardization among regional planning processes to achieve interregional coordination. Old Dominion agrees, recommending that the Commission provide guidance addressing the extent to which regional differences can be modified to enhance interregional transmission planning—potentially by requiring an interim compliance measure where regions report to the Commission on their progress, identify differences in regional transmission planning and/or cost allocation, and request guidance where needed. Southern Companies states

on reply that, while they have no objection to the Commission encouraging additional coordination, the Commission should not attempt to mandate (directly or indirectly) uniformity or standardization. Other commenters urge flexibility to accommodate regional differences.[355]

430. Several commenters emphasize the need for more consistent data formats, modeling, planning assumptions, planning standards and protocols, and evaluation procedures and metrics (among other elements of and tools used in the transmission planning process) between transmission planning regions or for use in interregional transmission planning to ensure that the proposed reforms are effective.[356] East Texas Cooperatives cite examples of inconsistent metrics and assumptions that they contend have hindered effective interregional planning between SPP and Entergy, including the use of: (1) different metrics to calculate available flowgate capacity at the seams; (2) different planning horizons; and (3) different types of proposed transmission upgrades in the long-term models for granting transmission service. Exelon asks the Commission to require the use of the same modeling assumptions and planning criteria, which should reflect actual expected operating conditions, when studying the impacts of a proposed

[355] *E.g.*, California Commissions; Dayton Power and Light; and NARUC.

[356] *E.g.*, WIRES; Wisconsin Electric Power Company; Pioneer Transmission; Organization of MISO States; Pennsylvania PUC; 26 Public Interest Organizations; East Texas Cooperatives; and ITC Companies.

interregional transmission facility on the reliability and congestion of neighboring systems. WIRES argues for the establishment of common interregional planning protocols by the Commission that can be employed by planners and stakeholders to guide development of interregional agreements on data, assumptions, and procedures that will be the foundation of genuine interregional planning processes. ITC Companies also recommends that the Commission require common assumptions and goals for long-term planning. Minnesota PUC and Minnesota Office of Energy Security recommend that project sponsors be required to provide usable data to all transmission planning entities that must study their projects.

431. Several commenters express concern that interregional planning processes could occur at different times and argue that a timeline should be established such that all planning regions consider interregional projects using the same timeline.[357] MidAmerican argues that interregional planning should be undertaken on a common time horizon, such as 20 years or longer. Organization of MISO States recommends that the Commission consider requiring the establishment of deadlines for submitting an interregional project for joint evaluation to avoid any negative impacts on each individual transmission planning region's planning process. ISO New England, however, argues against requiring interregional projects to be evaluated simultaneously by both regions or

[357] *E.g.*, Indianapolis Power & Light; California ISO; Organization of MISO States; and Solar Energy Industries and Large-scale Solar.

in joint sessions of both regions' stakeholders, asking instead that sequential evaluation by each region be allowed. Pioneer Transmission opposes sequential evaluation and recommends that the Commission require that interregional transmission planning agreements include specific milestones to ensure that proposed interregional projects are evaluated in a timely manner. Pioneer Transmission cautions, however, that interregional projects already before a transmission planning region should not be required to start over, which could possibly delay the overall evaluation process. MISO Transmission Owners agree that the proposed requirement should not interfere with existing transmission planning cycles.

432. American Transmission and the MISO Transmission Owners further recommend that interregional coordination procedures must allow for "out-of-cycle" reviews of interregional projects to address reliability issues. However, Wisconsin Electric Power Company suggests that the Commission require that adjacent planning regions align the timelines of their regional transmission planning processes to facilitate interregional coordination.

433. Several commenters support the Commission's proposed requirement that a proposed interregional transmission project must be included in each relevant regional

transmission plan to be subject to the interregional cost allocation method.[358] Duke supports the proposed requirement subject to the acknowledgement that inclusion in a plan does not mean that a given project will be constructed. Connecticut & Rhode Island Commissions contend that a region should not be required to accept an allocation of a transmission facility's costs unless the region approved the facility in its planning process and has identified concrete benefits that would accrue to the region. Organization of MISO States asks the Commission to clarify what would happen if, after neighboring regions' joint evaluation of a proposed interregional project, the project were found to benefit one region, but not the other. New England States Committee on Electricity supports the Commission's approach to interregional coordination as long as interregional transmission projects sponsored by one region will not be imposed involuntarily on another region. However, Anbaric and PowerBridge suggest that, once selected to go ahead, an interregional transmission project should bypass the planning region's normal procedures and be assigned to an interregional team to expedite and oversee the project, to ensure timely development of the facilities.

434. First Wind suggests that a region from which renewable energy is to be exported may not experience reliability, economic, or public policy benefits as a result of an interregional transmission project and, thus, the exporting region may not include the

[358] *E.g.*, New York ISO; New York Transmission Owners; and Transmission Dependent Utility Systems.

project in its regional transmission plan. To ensure that renewable resources are able to access markets in which they can command the best price, First Wind suggests that the regional state committee representing the importing region be able to identify that an interregional transmission project is necessary to achieve public policy objectives and consequently have it included in the exporting region's regional transmission plan.

**ii. Commission Determination**

435. The Commission requires the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions. The establishment of a procedure by which a public utility transmission provider will identify and jointly evaluate is necessary for facilitating the identification of interregional solutions that may resolve each region's needs more efficiently or cost-effectively. As a result, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are the more efficient and cost-effective solutions to meet the region's needs.

436. The Commission also requires the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. The submission of the interregional transmission project in each regional transmission planning process will trigger the procedure under which the public

utility transmission providers, acting through their regional transmission planning process, will jointly evaluate the proposed transmission project. This joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, for an interregional transmission facility to receive cost allocation under the interregional cost allocation method or methods developed pursuant to this Final Rule, the transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation.

437. Some commenters such as ISO/RTO Council express concern that joint evaluation of proposed interregional transmission facilities could involve the creation of a new set of planning criteria, while others such as Exelon stress the need for greater consistency in planning criteria and modeling assumptions used by neighboring regions. As a general matter, we note that joint evaluation of a proposed interregional transmission facility cannot be effective without some effort by neighboring transmission planning regions to harmonize differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project. We therefore direct, as part of compliance with the interregional transmission coordination requirements, that each public utility transmission provider, through its transmission planning region, develop procedures by which such differences can be identified and resolved for purposes of jointly evaluating the proposed interregional transmission facility. We leave to each

pair of neighboring regions, however, discretion in the way this requirement is designed and implemented and do not require that any particular planning horizons or criteria be used. In response to Minnesota PUC and Minnesota Office of Energy Security, we discuss in the opportunities for discrimination against non-incumbent transmission developers section the information that a transmission developer must provide to the transmission planning region in support of its transmission project proposal.[359]

438. Some commenters argue that the Commission should establish the timeframe within which regions must jointly evaluate interregional transmission projects. The Commission declines to specify a timeline for the interregional transmission coordination procedures or a deadline by which all interregional transmission projects must be submitted. Instead, the Commission expects public utility transmission providers in neighboring transmission planning regions to cooperate and develop timelines that allow for coordination and joint evaluation of interregional transmission projects in the same general time frame as each region's consideration of the transmission project. Furthermore, we disagree with those commenters that argue that there should be sequential evaluation of transmission projects, as opposed to evaluation on the regional and interregional levels in the same general time frame. However, we clarify for ISO New England that we will not require that interregional transmission projects be

[359] *See* discussion *supra* section III.B.3.d.ii.

evaluated simultaneously by both regions or in joint sessions of both regions' stakeholders.

439. Rather, we require that both regions conduct joint evaluation of an interregional transmission project in the same general timeframe. By same general time frame, the Commission expects public utility transmission providers to develop a timeline that provides a meaningful opportunity to review and evaluate through the interregional transmission coordination procedures information developed through the regional transmission planning process and, similarly, provides a meaningful opportunity to review and use in the regional transmission planning process information developed in the interregional transmission coordination procedures. Rather than provide further detailed guidance on this matter in this Final Rule that may unduly constrain the planning time line of each region for purposes of coordination with one or several neighboring regions, we prefer in the first instance to permit regions to develop appropriate timing arrangements with neighbors, which we will review on compliance.

440. American Transmission and the MISO Transmission Owners recommend that interregional transmission coordination procedures must allow for "out-of-cycle" reviews of interregional transmission projects to address reliability issues. The Commission believes that a requirement for ongoing constant reviews without regard to a defined planning cycle would be too burdensome. This Final Rule does not require such an "out-of-cycle" review, nor does it prohibit a region or a pair of regions from doing so, for

example if necessary to address a pressing reliability issue. Additionally, while the creation of a new planning cycle may be unnecessary, the Commission is requiring that coordination and joint evaluation must be conducted in the same general time frame as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project.

441. Furthermore, we decline to adopt suggestions to require adjacent transmission planning regions to align the timelines of their regional transmission planning processes. The Commission is providing flexibility, subject to certain requirements, in the design and implementation of procedures to govern the joint evaluation of interregional transmission facilities by neighboring transmission planning regions. To the extent public utility transmission providers in neighboring transmission planning regions identify changes to their regional transmission planning processes that are necessitated by implementation of interregional transmission coordination procedures, those transmission providers should implement those changes as part of their compliance filings submitted in response to this Final Rule.

442. In response to New England States Committee on Electricity's comment that interregional transmission coordination should begin with and respect the regional transmission planning process and resulting regional transmission plan, we note that we require in this Final Rule that the developer of a transmission project that would be located in more than one transmission planning region first must propose its transmission

project in the regional transmission planning process of each of those transmission planning regions. We expect each transmission planning region's review of that transmission project to be informed by and closely coordinated with the interregional transmission coordination procedures. Furthermore, the Commission did not propose in the Proposed Rule, and will not require in this Final Rule, that interregional transmission coordination procedures provide for the costs of an interregional transmission project sponsored by one transmission planning region to be involuntarily imposed on another transmission planning region.

443. Finally, the Commission agrees with Duke that having an interregional transmission facility in a regional transmission plan does not mean that it will be constructed. As in Order No. 890, the goal of this Final Rule is to establish procedures by which neighboring transmission planning regions will coordinate to jointly evaluate proposed transmission facilities, not to dictate which investment must be made or transmission projects must be built.[360] In response to Connecticut & Rhode Island Commissions, the Commission clarifies that public utility transmission providers in a transmission planning region will not be required to accept allocation of the costs of an interregional transmission project unless the region has selected such transmission facility in the regional transmission plan for purposes of cost allocation. That is, based on the

[360] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

information gained during the joint evaluation of an interregional transmission project, each transmission planning region will determine, for itself, whether to select those transmission facilities within its footprint in the regional transmission plan for purposes of cost allocation. Whether a transmission planning region would decide to select an interregional transmission facility in its regional transmission plan likely would be driven by the relative costs and benefits of the transmission project to that region. The Commission believes this effectively provides the "feedback loop" sought by Old Dominion.

444. The Commission declines to adopt the suggestion by Anbaric and PowerBridge that an interregional transmission project resulting from the interregional transmission coordination procedures be allowed to bypass the relevant regions' transmission planning processes and be automatically assigned to an interregional team. However, we do not preclude the public utility transmission providers in a pair of transmission planning regions from creating a separate process for developing interregional transmission facilities that have been in each relevant transmission planning region's plan. Instead, we provide transmission planning regions with flexibility to determine how to address an interregional transmission project. We reiterate that, to be eligible for interregional cost allocation, the interregional transmission facility must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission facility is proposed to be located.

445. Beyond the clarifications provided above, we decline to address the remaining requests to further delineate how neighboring transmission regions must jointly evaluate proposed interregional transmission facilities because such action could inadvertently impose requirements that are not appropriate for particular regions. Given the flexibility we have provided to public utility transmission providers in implementing the interregional transmission coordination requirements, the Commission determines it is unnecessary to adopt interim compliance requirements or other processes such as those suggested by Old Dominion.

446. We decline to adopt First Wind's suggestion that a transmission planning region should be required to include a transmission project intended to export renewable energy resources in its regional transmission plan if the regional state committee representing the importing region identifies the transmission project as necessary to achieve a public policy objective. As discussed above, whether an interregional transmission facility is to be selected in the regional transmission plan for purposes of cost allocation is a decision left to each transmission planning region. However, we will not preclude public utility transmission providers in neighboring transmission planning regions from voluntarily developing procedures such as those proposed by First Wind should they agree to do so as part of their interregional transmission coordination efforts.

447. In response to commenters' recommendations that the Commission provide for regional flexibility in developing and implementing interregional transmission

coordination, we reiterate the Commission's encouragement in the Proposed Rule that interregional transmission coordination procedures be tailored to best fit the needs of the public utility transmission providers in the regions involved while also meeting certain minimum requirements.[361]

448. Furthermore, as urged by PUC of Nevada, we are cognizant of existing interregional transmission coordination efforts and, by providing regional flexibility, intend to accommodate their various organizational structures, as suggested by WestConnect Planning Parties. Consistent with this approach, any public utility transmission provider that believes its existing interregional transmission coordination procedures, including those found in any interregional transmission planning agreement, already comply with the requirements of this Final Rule may indicate in its compliance filing how its existing procedures meet each requirement. If the existing procedures do not meet all of the requirements, the public utility transmission provider may propose revisions to its existing interregional transmission coordination procedures so that the procedures comply with this Final Rule.

449. Because we want to allow for regional flexibility, we decline to adopt commenters' suggestions that the Commission develop *pro forma* interregional

[361] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 117.

transmission coordination procedures or impose additional requirements as to what interregional transmission coordination should entail. As noted by Southern California Edison, planning coordination differs significantly at each RTO and ISO and among vertically integrated utilities, and we thus determine that *pro forma* interregional transmission coordination procedures are not appropriate at this time because it may not accommodate the differences among existing transmission planning regions. Moreover, the requirements that we adopt as interregional transmission coordination requirements in this Final Rule should be adequate guidance for public utility transmission providers.

450. We also note the Pennsylvania PUC's suggestion that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission planning regions negotiating bilateral coordination agreements. While we generally agree that various existing transmission planning agreements between regions may serve as models, we note that existing agreements reflect the needs of the regions that negotiated them. Thus, the Commission declines to require public utility transmission providers to adopt or model their coordination procedures on any particular agreement to coordinate transmission planning between two regions.

### b. Data Exchange

#### i. Comments

451. American Transmission supports the Proposed Rule's requirement that

interregional transmission planning agreements include an agreement to exchange planning data and information at least annually. American Transmission states that this requirement would help ensure that neighboring regions are aware of planning considerations as well as any transmission issues in neighboring regions. It also recommends that the Commission establish a time frame for a neighboring transmission planning region to respond to a transmission provider's request for planning information and data. SPP recommends that the Commission require interregional transmission planning agreements to include the specific procedures for sharing such information rather than only an agreement to do so.

452. Several commenters state that this exchange should be required to occur more often than annually.[362] NextEra states that the Commission should require the exchange of planning data and information at least as frequently as warranted by any material developments that either affect any neighboring region or interregional facility or may influence any interregional transmission plan. Organization of MISO States recommends that the Commission modify this element to require exchange of planning data and information at least semi-annually because transmission planning analysis can change over the course of a planning cycle due in part to changing modeling results and stakeholder input. Minnesota PUC and Minnesota Office of Energy Security recommend

[362] *E.g.*, Minnesota PUC and Minnesota Office of Energy Security; NextEra; and Organization of MISO States.

that the Commission require planning data and information exchanges between transmission planning regions to occur semi-annually to account for those project proposals that are requested to be reviewed out-of-cycle.

453. Transmission Dependent Utility Systems and Pennsylvania PUC express concern that this proposed element does not consider differences in the planning processes of each region. For example, Transmission Dependent Utility Systems state that the proposed planning data and information exchange requirement may be inadequate to address interregional transmission infrastructure concerns, and that transmission providers and stakeholders should be permitted to determine the type and frequency of meetings and planning information exchanges. Likewise, Pennsylvania PUC states that this requirement should accommodate different transmission planning regions' planning cycles.

### ii. Commission Determination

454. The Commission requires each public utility transmission provider, through its regional transmission planning process, to adopt interregional transmission coordination procedures that provide for the exchange of planning data and information at least annually. The sharing of data at least once a year will ensure that neighboring transmission planning regions are aware of each others' transmission plans and the assumptions and analysis that support such plans. In response to arguments that the Commission should require neighboring transmission planning regions to exchange data

more frequently, we note that this Final Rule provides that this information must be exchanged *at least* annually, thereby allowing each public utility transmission provider through its transmission planning region, the flexibility to decide to exchange information more frequently. If a pair of transmission planning regions anticipates that more frequent exchanges of planning data and information would improve interregional transmission coordination, then we encourage them to provide for such exchanges in their interregional transmission coordination procedures.

455. We agree with SPP that interregional transmission coordination procedures must include the specific obligations for sharing planning data and information rather than only an agreement to do so. A clear description of the procedures that will be used to exchange planning data and information will help the Commission, transmission customers, and other stakeholders to better determine if each public utility transmission provider is fulfilling its obligations consistent with this Final Rule. However, we will not dictate the specific procedures or the level of detail for the procedures pursuant to which planning data and information must be exchanged. Consistent with the comments of Transmission Dependent Utility Systems and Pennsylvania PUC, we allow each public utility transmission provider, through its transmission planning region, to develop procedures to exchange planning data and information, which we anticipate will reflect the type and frequency of meetings that are appropriate for each pair of regions and will accommodate each pair of region's planning cycles.

### c. Transparency

#### i. Comments

456. Pennsylvania PUC supports the proposed requirement that interregional transmission planning agreements include a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process. Duke requests the Commission clarify that information relating to the interregional transmission planning process can be maintained on an existing transmission provider's website or regional transmission planning website.

457. In addition, MISO Transmission Owners suggest that all transmission providers offering transmission service or interconnection service under a tariff (including a non-jurisdictional tariff) should be required to make publicly available their business practice manuals or other documentation specifically detailing the assumptions and criteria used in comparably evaluating all proposed transmission and generation projects, including the identification and treatment of third-party impacts.

#### ii. Commission Determination

458. The Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a website or e-mail list for the communication of information related to interregional transmission coordination procedures. The Commission clarifies that information related to interregional transmission coordination may be maintained on an existing public utility transmission

provider's website or a regional transmission planning website. However, the information should be posted in such a way that stakeholders are able to distinguish between information related to interregional transmission coordination and information related to regional transmission planning.

### d. Stakeholder Participation

#### i. Commission Proposal

459. In the Proposed Rule, the Commission did not specifically address the issue of stakeholder participation with regard to the coordination of transmission planning activities undertaken by neighboring transmission regions.

#### ii. Comments

460. Some commenters discuss the need for utilities and stakeholders to participate in the process of developing interregional planning agreements. Transmission Access Policy Study Group states that interregional transmission planning agreements must be inclusive, open, and collaborative. Both Transmission Access Policy Study Group and East Texas Cooperatives state that transmission dependent utilities should have the opportunity to participate in their development and implementation. Transmission Access Policy Study Group states that, without such a requirement, the Commission would not be fulfilling its responsibility under FPA section 217(b)(4) to facilitate planning to meet the needs of all load-serving entities. Wisconsin Electric Power Company requests that the Commission explicitly ensure that stakeholders have the

opportunity to participate in the development of these agreements.

461. Some commenters contend that the interregional transmission planning requirements described in the Proposed Rule could be significantly improved with respect to stakeholder participation. New York PSC states that the Commission should articulate that meaningful participation in the planning process is necessary, including the opportunity to provide input concerning how studies are conducted and solutions are identified. Transmission Dependent Utility Systems contend that it is just as important for transmission customers to be able to participate in interregional transmission planning as it is for them to be able to participate in regional transmission planning.

462. Integrys states that because stakeholder involvement and input is necessary to ensure proper planning and evaluation of projects, the Commission should adopt a stakeholder participation requirement in any Final Rule. Xcel states that the interregional coordination necessary to support the development of larger-scale, interregional transmission projects (particularly those that are needed to integrate renewable energy resources) must engage stakeholders, and especially state regulatory agencies, in the development of processes that address the specific needs and requirements of the participating regions. Without the involvement of state agencies, which ultimately decide which transmission facility will be built, Xcel contends that interregional transmission planning processes will not result in the construction of needed transmission.

463. Energy Future Coalition states that interregional transmission planning must be

both participatory and analytically robust by engaging all interested parties, including utilities, states, renewable generation developers, environmental interests, and consumer interests.

464. Some commenters express concern that, even if the proposed interregional transmission planning requirements provide for stakeholder participation, such participation can require significant resources from stakeholders. NARUC and Massachusetts Departments claim that limited human resources and budgets make it difficult for state commissions and other stakeholders to participate in additional transmission planning processes. Massachusetts Departments suggest that any Final Rule should take these challenges into account and consider mechanisms to address them. Similarly, California Commissions comment that states must have access to adequate resources to support state involvement in interregional coordination processes and that the Commission could consider requiring stakeholder support beyond that provided through the ARRA-funded interconnectionwide transmission planning initiatives.

### iii. Commission Determination

465. We agree with those commenters that argue stakeholder participation is an important component in interregional transmission coordination to ensure the goals of improving coordination between neighboring transmission planning regions and identifying interregional transmission facilities that can address transmission needs more efficiently or cost-effectively than separate intraregional transmission facilities.

However, this Final Rule does not require the interregional transmission coordination procedure to meet the requirements of the planning principles required for local planning (under Order No. 890) and regional planning (under this Final Rule).[363] Because we require in this Final Rule that an interregional transmission facility must be selected in each relevant regional transmission plan for purposes of cost allocation to be eligible for interregional cost allocation, stakeholders will have the opportunity to participate fully in the consideration of interregional transmission facilities during the regional transmission planning process.[364] Furthermore, we believe that stakeholder participation in the various regional transmission planning processes will enhance the effectiveness of interregional transmission coordination. To facilitate stakeholder involvement, this Final Rule requires the public utility transmission providers to make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[365]

466. We also agree with commenters that discuss the importance of transmission customer and stakeholder participation in the development of the interregional transmission coordination procedures necessary to comply with the requirements in this

[363] Of course, nothing precludes public utility transmission providers in neighboring transmission planning regions from choosing to meet those requirements.

[364] *See* discussion *supra* P 150.

[365] This information must be made available subject to appropriate confidentiality protections and CEII requirements.

Final Rule. Therefore, we require that each public utility transmission provider give stakeholders the opportunity to provide input into the development of its interregional transmission coordination procedures and the commonly agreed-to language to be included in its OATT.

467. The Commission appreciates the concerns of NARUC and others regarding the effect budgetary limitations could have on effective stakeholder participation in interregional transmission coordination activities. As discussed above in the regional transmission planning section[366] and consistent with Order No. 890, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

### e. Tariff Provisions and Agreements for Interregional Transmission Coordination

#### i. Commission Proposal

468. In the Proposed Rule, the Commission proposed to require that coordination between neighboring transmission planning regions be reflected in an interregional transmission planning agreement to be filed with the Commission.[367]

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[366] *See* discussion *supra* section III.A.3.

[367] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114.

### ii. Comments

469. Several commenters express support for the Commission's proposal to require neighboring regions to enter into interregional transmission planning agreements.[368] They also emphasize, however, that planning regions should be able to structure planning agreements so that each region is a full, equal partner and no region can force projects or costs onto other regions in a manner that is inconsistent with the agreement. Edison Electric Institute further emphasizes that these planning agreements cannot replace strong interregional coordination to address interregional impacts.

470. Other commenters argue that the Commission should accept the submission of existing interregional agreements, with necessary modifications, to comply with the Final Rule.[369] American Transmission and MISO Transmission Owners state that when reviewing existing interregional agreements to determine their compliance with the Final Rule, if the Commission determines that modifications to these agreements are necessary, the public utility transmission providers and their stakeholders should be given the opportunity to address and submit revisions.

471. Some commenters suggest that interregional coordination procedures should be

[368] *E.g.*, National Grid; New York Transmission Owners; and Edison Electric Institute.

[369] *E.g.*, FirstEnergy Service Company; American Transmission; and MISO Transmission Owners.

incorporated into public utility transmission providers' OATTs. Ad Hoc Coalition of Southeastern Utilities suggests that as an alternative to the interregional agreement, the Commission should consider adopting an additional planning principle that permits public utility transmission providers to explain how they address the types of matters that the Proposed Rule would require to be included in such interregional agreements. ColumbiaGrid further contends that transmission providers in the Western Interconnection should be required to include in their OATTs only the regional planning group and WECC processes and information regarding their existing relationship, and that they should not be required to divert resources to developing formal agreements to be filed with the Commission. Bonneville Power suggests that the Commission require transmission providers to include coordination requirements as part of the transmission planning processes outlined in their OATTs, but without specific details about how individual projects would be planned and developed. It states that this would allow transmission providers to enter into voluntary agreements and to focus on developing higher priority projects. Transmission Dependent Utility Systems state that each public utility transmission provider's interregional transmission planning process should be included in the OATT, subject to effective Commission and stakeholder scrutiny on an ongoing basis.

472. California ISO also contends the proposed requirements are problematic for the ISO in that it would not be able to develop an interregional transmission planning

agreement applicable to all of its neighboring balancing authority areas because many of its neighboring balancing authorities have different legal charters and are subject to different laws, regulations, and requirements.

473. Several commenters raised concerns about the proposed interregional transmission planning agreements with respect to non-jurisdictional transmission providers. Western Area Power Administration requests that the Final Rule acknowledge that interregional transmission planning-related agreements would need to account for the status and statutory requirements of non-public utility transmission providers before they may be executed. Large Public Power Council states its members will commit to voluntarily participate in interregional transmission planning processes, but that its members have limited authority to enter into agreements that include, among other things, an obligation to pay construction costs or a requirement to defer to regional or interregional planning authorities. Omaha Public Power District states that it plans to participate voluntarily in an interregional transmission planning process, but notes that its agreements to do so would not be subject to the Commission's jurisdiction or enforcement. Nebraska Public Power District expresses the same concerns regarding the lack of clarity in the commitments that it would be required to make as a result of the proposed interregional transmission planning agreements. Nebraska Public Power District also commits to participate in interregional transmission planning processes; however, it contends that it cannot make such commitment outside of its current RTO membership and the related

protection against violating state law and that its authority to enter into binding agreements is limited consistent with state sovereignty.[370]

474. Several commenters argue that the Commission should require non-jurisdictional entities to comply with the proposed interregional transmission planning requirements. Westar states that power flows on a non-jurisdictional entity's system can affect facilities in a jurisdictional entity's system, and vice-versa. Similarly, MISO Transmission Owners state that requiring non-jurisdictional entities to participate would ensure effective interregional transmission planning and coordination and address seams issues. NextEra states that to facilitate broad-based participation by all relevant entities, the Commission should invoke its authority under FPA section 211A to require unregulated transmitting utilities to participate in the interregional transmission planning process.

### iii. Commission Determination

475. In light of the comments received, the Commission declines to require that coordination between the public utility transmission providers in pairs of neighboring transmission planning regions be reflected in a formal interregional transmission planning agreement filed with the Commission, as was proposed in the Proposed Rule. Instead, as recommended in part by Ad Hoc Coalition of Southeastern Utilities, ColumbiaGrid,

[370] Comments addressing specific statutory provisions that may limit non-jurisdictional participation in this regard are addressed in the discussion of the Commission's legal authority to undertake reforms regarding regional transmission planning. *See* discussion *infra* section III.A.2 of this Final Rule.

Bonneville Power, and Transmission Dependent Utility Systems, we require that the public utility transmission providers in each pair of neighboring transmission planning regions, working through their regional transmission planning processes, must develop the same language to be included in each public utility transmission provider's OATT that describes the interregional transmission coordination procedures for that particular pair of regions.[371] Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission coordination agreement filed on compliance for approval by the Commission.[372]

476. We find that implementing the interregional transmission coordination requirements in this Final Rule through their incorporation in each public utility transmission provider's OATT, instead of requiring an interregional transmission

[371] Consistent with the approach taken in Order Nos. 890 and 890-A, public utility transmission providers may use web-posted business practice manuals to describe planning-related processes. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1653; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 990.

[372] However, even if a public utility transmission provider voluntarily enters into such an agreement, its OATT must still provide enough description for stakeholders to follow how interregional transmission coordination will be conducted, with links included to the actual agreement where the details can be found. *See United States Dep't of Energy - Bonneville Power Admin.*, 124 FERC ¶ 61,054, at P 65 (2008) (requiring Avista, Puget and Bonneville Power "to provid[e] additional detail in their Attachment Ks on the WECC's [Transmission Expansion Planning Policy Committee's] process or providing direct links (i.e., URLs) to the appropriate documents on the WECC website where the processes to coordinate information and planning efforts [between several regional planning groups] are discussed").

planning agreement, will fulfill our objective to improve interregional transmission coordination and provide adequate transparency with regard to the obligations imposed on public utility transmission providers. Further, commenters persuade us that this approach would facilitate the participation of non-public utility transmission providers in an interregional transmission coordination efforts.

477. In response to commenters' arguments that the Commission should accept the submission of existing interregional agreements on compliance, we agree provided the compliance filing explains how the existing agreement satisfies the requirements of this Final Rule. The Commission will address the adequacy of such an existing agreement on compliance.

478. We decline to adopt Bonneville Power's recommendation that these procedures omit specific details about how individual transmission projects would be planned and developed, because we require each set of interregional transmission coordination procedures to include a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions.

479. We do not find convincing California ISO's argument that it will be problematic for it to develop interregional transmission coordination procedures with all of its neighboring balancing authority areas due to the differences among them. Just as reliable transmission operation of interconnected transmission systems requires coordination among neighboring utilities and regions—some of which is required by mandatory

reliability standards, transmission planning of interconnected transmission systems requires some degree of coordination among neighboring utilities and regions. We conclude that this Final Rule provides for sufficient regional flexibility to allow the California ISO to develop in cooperation with its neighboring balancing authority areas interregional transmission coordination procedures that accommodate their differences.

480. We agree with commenters that interregional transmission coordination should be structured in such a way that no public utility transmission provider in a transmission planning region should be permitted to force transmission projects or costs onto another region contrary to the agreed upon interregional transmission coordination procedures

incorporated into the relevant public utility transmission providers' OATTs pursuant to this Final Rule.

481. Because we are implementing the interregional transmission coordination requirements adopted in this Final Rule through incorporation of the same language into each public utility transmission provider's OATT rather than through formal agreements, we find comments presenting concerns that non-public utility transmission providers are unable to be party to interregional transmission planning agreements to be moot. Furthermore, we do not believe that it is necessary to address here those commenters that ask us to require non-public utility transmission providers to participate in interregional transmission coordination efforts. We believe such concerns are premature, as we are

encouraged by the non-public utility transmission providers who expressed their intent to participate in interregional transmission coordination efforts in their comments in response to the Proposed Rule. Additional discussion of non-public utility transmission provider participation in the reforms adopted in this Final Rule, including the interregional transmission coordination requirements, is in the reciprocity section below.[373]

## IV. Proposed Reforms: Cost Allocation

482. The Commission requires, as part of this Final Rule, that each public utility transmission provider have in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan ("regional cost allocation"); and that each public utility transmission provider within a transmission planning region develop a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently and cost-effectively ("interregional cost allocation"). The OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. Each of the regional cost allocation and interregional cost allocation methods must adhere to the respective general cost allocation principles as set forth

[373] *See* discussion *infra* section V.B.

below.[374] Subject to these general cost allocation principles, public utility transmission providers in consultation with stakeholders have the opportunity to develop the appropriate cost allocation methods for their new regional and interregional transmission facilities. In the event that no agreement among public utility transmission providers in a region or pair of regions can be reached, the Commission will use the record in the relevant compliance filing proceeding(s) as a basis to develop a cost allocation method or methods that meets the Commission's requirements.

483. The requirements established below are designed to work in tandem with the transmission planning requirements established above to identify more appropriately the benefits and the beneficiaries of new transmission facilities so that transmission developers, planners and stakeholders can take into account in planning who would bear the costs of transmission facilities, if constructed.

## A. Need for Reform Concerning Cost Allocation

### 1. Commission Proposal

484. In the Proposed Rule, the Commission noted that its responsibility under sections 205 and 206 of the FPA to ensure that transmission rates are just and reasonable and not

[374] For purposes of this Final Rule, a regional transmission facility is a transmission facility located entirely in one region. The Proposed Rule sometimes called such a facility a regional facility and sometimes an intraregional facility. An interregional transmission facility is one that is located in two or more transmission planning regions. A transmission facility that is located solely in one transmission planning region is not an interregional transmission facility.

unduly discriminatory or preferential is not new, nor is the Commission's recognition of the cost causation principle. However, the Commission explained that the circumstances in which it must fulfill its statutory responsibilities change with developments in the industry, such as changes with respect to the demands placed on the grid. For example, the expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standards, has contributed to the rapid growth of renewable energy resources that are frequently remote from load centers.

485. The Commission stated that challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. The Commission noted that constructing new transmission facilities requires a significant amount of capital and, therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. The Commission explained, however, that there are few rate structures in place today that provide both for analysis of the beneficiaries of a transmission facility that is proposed to be located within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region, and for corresponding allocation and recovery of the facility's costs. The Commission stated that lack of such rate structures creates

significant risk for transmission developers that they will have no identified group of customers from which to recover the cost of their investment. With regard to cost allocation within RTO or ISO regions, the Commission noted that cost allocation issues are often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair, particularly for RTOs and ISOs that encompass several states.

486. The Commission further noted that the risk of the free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. The Commission explained that, on one hand, a cost allocation method that relies exclusively on a participant funding approach,[375] without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs would be allocated to entities that will receive no benefit from a

[375] Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. The Proposed Rule cited several examples of regions relying principally or exclusively on the participant funding approach to cost allocation. Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128.

transmission facility, then those entities are more likely to oppose selection of the facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the facility's construction.

487. In light of these challenges and recent developments affecting the industry, the Commission stated concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities and, thus, may result in rates that are not just and reasonable or are unduly discriminatory or preferential.[376] The Commission proposed the cost allocation requirements discussed in further detail below to address this concern.

### 2. Comments on Need for Reform

488. A number of commenters generally support the cost allocation requirements proposed by the Commission.[377] For example, ITC Companies state that the Commission has correctly concluded that reform with respect to transmission cost allocation methods is necessary. AWEA argues that issues related to cost allocation impede transmission development required to address increased demand, meet national

[376] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148-54.

[377] *E.g.*, Transmission Access Policy Study Group; AWEA; Northeast Utilities; ITC Companies; Energy Future Coalition Group; MidAmerican; MISO; NextEra; E.ON Climate Renewables North America; Exelon; Iberdrola Renewables; WIRES; Western Grid Group; and Pennsylvania PUC.

energy and environmental goals, and create an intelligent, secure, and reliable transmission network. Clean Line argues that implementation of a cost allocation method is critical to the development of new infrastructure. Multiparty Commenters argue that a fair allocation of the costs of new transmission can be facilitated by acknowledging that the cost of transmission is a small portion of the delivered cost of electricity, generally ten percent or less, whereas the costs of a single project may be significant for the builders of that project. Solar Energy Industries urge the Commission to use its authority to alleviate impediments to building new transmission lines for renewable energy and other system needs to promote a robust competitive market that will benefit consumers and the environment.

489. Many commenters also support aligning transmission planning and cost allocation more closely.[378] Transmission Dependent Utility Systems state that it is virtually impossible to separate transmission planning from transmission cost allocation. Exelon argues that fair, efficient, and legal cost allocation should follow the manner in which its system is planned. Integrys agrees with linking cost allocation rules with transmission planning, but cautions that the transmission planning process is not a substitute for the

[378] *E.g.*, Atlantic Grid; ITC Companies; Sunflower and Mid-Kansas; MISO; Pennsylvania PUC; PHI Companies; Colorado Independent Energy Association; Energy Future Coalition Group; PSC of Wisconsin; CapX2020; and Wind Coalition.

cost allocation process.

490. A number of commenters supporting closer alignment between planning and cost allocation state that existing ISO and RTO transmission planning and cost allocation processes already may satisfy the proposal to align transmission planning and cost allocation more closely.[379] AEP and SPP believe that their existing transmission planning and cost allocation processes satisfy many of the Commission's proposed requirements. Similarly, MISO Transmission Owners state that cost allocation in MISO is already closely tied to the transmission planning process. Organization of MISO States points to MISO filings that address cost allocation issues.

491. WIRES asks the Commission to ensure that the planning process not be unduly influenced by those that seek to redirect potential cost allocation liability. Illinois Commerce Commission believes it is unduly discriminatory for a state to be required to bear costs for transmission expansion projects under a cost sharing arrangement but have no decisional authority for projects outside their state. Where a regional state committee exists, Illinois Commerce Commission recommends that a process be carved out by which the regional state committee's board of directors has the opportunity to review and decide on the reasonableness of each of the RTO's proposed transmission expansion projects for which regional cost allocation would apply.

[379] *E.g.*, SPP; AEP; MISO Transmission Owners; Organization of MISO States; California PUC; and Pacific Gas & Electric.

492. A number of commenters express concern with the Commission's proposal to impose generic regional and interregional cost allocation requirements.[380] Some commenters argue specifically that there is no need for the Commission's proposed cost allocation reforms.[381] For example, Northern Tier Transmission Group argues that the Proposed Rule does not present a factual basis for expanding the scope of the cost allocation requirement to every project contained in a regional transmission plan. It requests that the Commission confirm that the Proposed Rule is not intended to apply to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures. If the Proposed Rule is intended to apply to all new transmission projects in a region's transmission plan, Northern Tier Transmission Group urges that the Proposed Rule be rejected. It also is concerned that shifting the burden of cost allocation for every project onto the regional transmission planning process will create an unnecessary burden on a region's collective transmission providers. Westar states that the transmission planning selection process is critical to ensure that only transmission

[380] *E.g.*, Arizona Public Service Company; Bonneville Power; California Transmission Planning Group; Tucson Electric; Western Area Power Administration; California Commissions; California ISO; Eastern Massachusetts Consumer-Owned System; New York PSC; Coalition for Fair Transmission Policy; Connecticut & Rhode Island Commissions; Large Public Power Council; National Grid; and Southern California Edison.

[381] *E.g.*, Ad Hoc Coalition; Southern Companies; Salt River Project; and Nebraska Public Power District.

projects that meet the various regional requirements are constructed and their costs recovered as part of tariff rates.

493. North Carolina Agencies contend that the Commission has not established that current cost allocation methods are unjust and unreasonable. Nebraska Public Power District argues that the Proposed Rule does not contain any record evidence demonstrating the need for generic rate reform and states that transmission investment has substantially increased in recent years. Salt River Project argues that the primary barriers to renewable resource development are delays and denial of siting and other permits, not transmission funding. California Municipal Utilities suggest that fewer remote resources are needed because more local renewable resources are being developed and, therefore, the need for cost allocation reforms must be re-examined. Indianapolis Power and Light believes that existing tariff requirements and ongoing proceedings will achieve the Commission's stated objective without the uncertainty of a parallel rulemaking process.

494. MEAG Power responds to Multiparty Commenters' assertion regarding the cost of transmission expansion by arguing that investments of the size actually needed to build out the transmission system, if allocated to load, would raise its native load customers' transmission costs dramatically. Sacramento Municipal Utility District states that, even if Multiparty Commenters' assertion were true, it is irrelevant to the establishment of a just

and reasonable transmission rate whether it comprises a small or large portion of the cost of delivered power.[382] Large Public Power Council raises arguments similar to those raised by both MEAG Power and Sacramento Municipal Utility District.

### 3. Commission Determination

495. The Commission concludes that it is necessary and appropriate to adopt the cost allocation requirements described in further detail below for public utility transmission providers. The Commission finds that, without these minimum requirements in place, cost allocation methods used by public utility transmission providers may fail to account for the benefits associated with new transmission facilities and, thus, result in rates that are not just and reasonable or are unduly discriminatory or preferential.

496. In Order No. 890, the Commission found that there is a close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan.[383] The Commission explained that knowing how the costs of transmission facilities would be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who

[382] Sacramento Municipal Utility District (citing *Farmers Union Central Exchange v. FERC*, 734 F.2d 1486, 1508 (D.C. Cir. 1984)).

[383] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

will pay the associated costs.[384] In light of that relationship, the Commission directed public utility transmission providers to identify the cost allocation method or methods that would apply to transmission facilities that do not fit under previously existing rate structures.[385] After several rounds of compliance filings, the Commission accepted various public utility transmission providers' proposals as in compliance with Order No. 890. Particularly in transmission planning regions outside of the RTO and ISO footprints, several of the cost allocation methods that the Commission accepted relied exclusively on a participant funding approach to cost allocation.[386] The Commission did not address cost allocation for interregional transmission facilities in Order No. 890.

497. We conclude that, in light of changes within the industry and the implementation of other reforms in this Final Rule, the existing requirements of Order No. 890 are no longer adequate to ensure rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. While the existing cost allocation methods may have sufficed in the past, as we note above, the circumstances in

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[384] *Id.*

[385] *Id.* P 558.

[386] *See, e.g.*, *El Paso Electric Co.*, 124 FERC ¶ 61,051 (2008); *Xcel Energy Services, Inc. - Public Service Co. of Colorado*, 124 FERC ¶ 61,052 (2008); *South Carolina Electric & Gas Co.*, 127 FERC ¶ 61,275 (2009). *Entergy Services, Inc.*, 127 FERC ¶ 61,272 (2009). *See also Avista Corp.*, 128 FERC ¶ 61,065 (2009); *Idaho Power Co.*, 128 FERC ¶ 61,064 (2009).

which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on the transmission grid. The comments in this proceeding make clear that the pace of change has accelerated in recent years, such as the expansion of regional power markets, which has led to a growing need for transmission facilities that cross several utility, RTO, ISO or other regions. The industry's continuing transition also has enabled greater utilization of resources (e.g., reserve sharing) resulting in, among other effects, broader diffusion of the benefits associated with transmission facilities. Additionally, the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus a growing need for transmission facilities to access remote resources, often traversing several utility and/or ISO/RTO regions.

498. The challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. Within RTO or ISO regions, particularly those that encompass several states, the allocation of transmission costs is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived by all stakeholders as reflecting a fair distribution of benefits. In other regions, few rate structures are currently in place that reflect an analysis of the beneficiaries of a transmission facility and for the corresponding cost allocation of the transmission facility's cost. Similarly, there are few rate structures

in place today that provide for the allocation of costs of interregional transmission facilities.

499. We agree with many commenters that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process. Under the regional transmission planning and interregional transmission coordination requirements adopted in this Final Rule,[387] public utility transmission providers, in consultation with stakeholders, will identify, evaluate, and determine the set of transmission facilities that will meet the combined needs of the region or neighboring pairs of regions, respectively. This necessarily includes a determination by the region that the benefits associated with that set of transmission facilities outweigh the costs. Failing to address the allocation of costs for these transmission facilities in a way that aligns with the evaluation of benefits through the transmission planning process could lead to needed transmission facilities not being built, adversely impacting ratepayers.

500. In general and as discussed elsewhere in this Final Rule, the Commission requires a public utility transmission provider to participate in a regional transmission planning

[387] *See* discussion *supra* sections III.A and III.C.

process and to coordinate transmission planning with public utility transmission providers in neighboring transmission planning regions in a manner that aligns transmission planning and cost allocation processes. Additionally, the OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. As some commenters point out, transmission facilities that are in a transmission plan to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, address economic considerations, or enable compliance with Public Policy Requirements. Because such purposes involve the identification of expected beneficiaries, either explicitly or implicitly, establishing a closer link between transmission planning and cost allocation will ensure that rates for Commission-jurisdictional service appropriately account for benefits associated with new transmission facilities.

501. We recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. We believe that a transparent transmission planning process is the appropriate forum to address these issues. By linking transmission planning and cost allocation through the transmission planning process, we seek to increase the likelihood that transmission facilities in regional transmission plans are actually constructed.

502. Turning to specific comments on this topic, we are not persuaded to adopt Illinois

Commerce Commission's proposal for separate review and decision by a committee of state regulators on the reasonableness of proposed transmission expansion projects for which regional cost allocation would apply. As explained above,[388] this Final Rule builds on Order No. 890's requirement that a public utility transmission provider have open and transparent transmission planning processes in which we encourage states or state committees to be involved. Additionally, as required by this Final Rule, through the transmission planning process, the public utility transmission providers and other parties, including state regulators, will have opportunities to participate in the identification of transmission needs. We decline, however, to mandate veto rights for state committees, but do not preclude public utility transmission providers from proposing such mechanisms on compliance if they choose to do so.[389]

503. In response to Northern Tier Transmission Group's concern that applying the new cost allocation requirements to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures will shift costs and create unnecessary burdens, we clarify that the cost allocation requirements of this Final Rule

[388] *See* discussion *supra* section III.A.

[389] For example, Entergy's OATT allows Entergy's committee of state regulators to add a project to Entergy's transmission plan upon unanimous vote of the committee members. *See Entergy Arkansas, Inc.*, 133 FERC ¶ 61,211 (2010).

apply only to new transmission facilities[390] selected in regional transmission plans for purposes of cost allocation.

### B. Legal Authority for Cost Allocation Reforms

#### 1. Commission Proposal

504. The Commission explained in the Proposed Rule that, to ensure that transmission rates are just and reasonable, the costs of jurisdictional transmission facilities must be allocated in a way that satisfies the "cost causation" principle. It noted that the D.C. Circuit defined the cost causation principle stating that "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[391] Moreover, the Commission noted that while the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it,[392] the D.C. Circuit has explained that cost causation "does not require exacting precision in a ratemaking agency's allocation decisions."[393]

505. The Commission explained that, while costs generally have been allocated through

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[390] *See* discussion *supra* P 161.

[391] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (*K N Energy*).

[392] *Illinois Commerce Commission*, 576 F.3d 470 at 476-77 ("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.").

[393] *MISO Transmission Owners*, 373 F.3d 1361 at 1371.

voluntary agreements, the cost causation principle is not limited to such arrangements. If it were, the Commission could not address free rider problems associated with new transmission investment and could not ensure that transmission rates are just and reasonable and not unduly discriminatory. The Commission stated that it may determine that an entity is a beneficiary of a transmission facility even if it has not entered a voluntary arrangement with the public utility transmission provider that is seeking to recover the costs of that transmission facility.

506. The Commission noted that it has expressed a willingness to make such a determination, as when presented with concerns about parallel path flow.[394] In such cases, a public utility transmission provider may propose a transmission service rate that would account for unauthorized use of its system.[395] The Commission noted that it has cautioned against the hasty submittal of such unilateral filings and prefers resolution of

[394] The Commission has described the phenomenon of parallel path flow as follows: "In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself along the lines of least resistance. This parallel path flow is sometimes called 'loop flow.'" *Indiana Michigan Power Co. and Ohio Power Co.*, 64 FERC ¶ 61,184, at 62,545 (1993).

[395] *See, e.g.*, *Amer. Elec. Power Svc. Corp.*, 49 FERC ¶ 61,377, at 62,381 (1989) (*AEP*).

parallel path flow issues on a consensual, regional basis.[396] If necessary, however, it would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.

507. The Commission also stated that it has affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving MISO and PJM. Specifically, the Commission explained that it directed MISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other's footprint.[397] It subsequently conditionally accepted a proposal by MISO and PJM on the grounds that it "more accurately identifies the beneficiaries and allocates the associated costs."[398]

508. The Commission noted that courts have accepted the application of the cost

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[396] *Id*.; *see also Southern California Edison Co*., 70 FERC ¶ 61,087, at 61,241-42 (1995).

[397] *Midwest Indep. Transmission Sys. Operator, Inc*., 109 FERC ¶ 61,168, at P 60 (2004) (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 106 FERC ¶ 61,251, at P 56-57 (2004)). The Commission noted that MISO and PJM had committed in a Joint Operating Agreement to develop such a method for allocating the costs of certain facilities through their joint regional planning committee. *Id*. The Commission did not base the above-noted directive on the existence of the Joint Operating Agreement, which MISO and PJM developed to comply with a previous Commission directive. *See Alliance Cos*., 100 FERC ¶ 61,137, at P 48, 53 (2002).

[398] *Midwest Indep. Transmission Sys. Operator, Inc*., 113 FERC ¶ 61,194, at P 10 (2005). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084 (2008); *Midwest Indep. Transmission Sys. Operator, Inc*., 129 FERC ¶ 61,102 (2009).

causation principle in this way. For example, the D.C. Circuit addressed this issue in connection with a MISO proposal to recover administrative costs through a charge that would apply to transmission loads subject to MISO's OATT rates.[399] The court found that the Commission's system-wide benefits analysis met the requirements of the cost causation principle, that is, to compare "the costs assessed against a party to the burdens imposed or benefits drawn by that party."[400]

### 2. Comments on Legal Authority

509. Several entities comment in support of the Commission's legal authority to allocate costs of new transmission facilities based on a beneficiary pays approach.[401] AEP asserts that the Commission's proposed cost allocation principles comport with the legal requirements on cost allocation articulated by the U.S. Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission v. FERC*.[402] Further, AEP states that while the courts have found that the allocation of transmission expansion costs in rates must follow the "cost causation" principle, the courts have explained that all beneficiaries

[399] *MISO Transmission Owners*, 373 F.3d 1361. The D.C. Circuit stated that the subject costs "are primarily MISO's startup expenses – particularly those pertaining to the MISO Security Center – and certain expenses pertaining to the creation and administration of MISO's open access tariff." *Id*. at 1369.

[400] *Id*. at 1367.

[401] *E.g.*, Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[402] 576 F.3d 470 (7th Cir. 2009) (*Illinois Commerce Commission*).

"cause" costs for the purpose of applying this principle. Thus, from AEP's perspective, the Commission's proposal to require allocation of costs to beneficiaries is fully consistent with the legal precedent. Iberdrola Renewables and American Transmission agree. American Transmission cautions, however, that care be taken in how precisely the costs of a transmission project are linked to beneficiaries, given that the benefits and beneficiaries of a particular project may change over time, particularly in the case of a large project that provides regional and interregional benefits. Allegheny Energy Companies state that although the *Illinois Commerce Commission* decision found that the Commission did not provide sufficient evidence to justify adoption of the postage-stamp cost allocation method in PJM, it did not reject the method outright, instead requiring the Commission only to provide further justification assuring that this method results in a just and reasonable rate that satisfies the principle that rates required to be paid by a customer must have some relationship to the costs caused or benefits received by that customer.

510. LS Power asserts that there is nothing in the FPA that precludes the Commission from allocating costs incurred by one transmission provider in a region to entities nominally taking service under the tariffs of other transmission providers, or to those other transmission providers themselves for the benefits they receive with respect to their own uses of the regional transmission grid. On the contrary, it explains that allocating costs only to customers located within the corporate boundaries of the utility that owns the transmission facilities will over-allocate costs to such customers and allow other

beneficiaries to become free riders. LS Power concludes that the Commission has exclusive jurisdiction over interstate transmission services, and therefore, the authority and the responsibility to define interstate transmission services—here regional transmission services—and to identify the beneficiaries of those services that are responsible for costs incurred by regional transmission providers.

511. Illinois Commerce Commission agrees with the Commission's decision that, when applying the cost causation principle, the Commission may allocate costs of a transmission facility to a beneficiary identified through an appropriate process, such as a Commission-approved transmission planning process, even if that beneficiary has not entered into a voluntary arrangement with a public utility that is seeking to recover the costs of that facility. However, it asserts that the process must take into account the restrictions on allocation to beneficiaries set forth in *Illinois Commerce Commission*, in which cost causers are primary, and beneficiaries may be taken into account only to the extent that, without the developer's expectation of receiving revenues from such a party, the project "might not have been built, or might have been delayed." Illinois Commerce Commission asserts that an unduly discriminatory socialization of costs based on speculation that uncertain future costs will offset the discrimination does not support a finding of just and reasonable rates.[403]

[403] In reply, PPL Companies assert that Illinois Commerce Commission overstates

(continued…)

512. A number of commenters agree that a free rider problem exists in transmission development and that the Commission should bring certainty to cost allocation rules to address this concern.[404] NextEra states that any project that provides benefits to entities, other than the sponsoring entity, creates an incentive for an individual beneficiary to defer investment in hopes that others will fund the project's development, and this has led to stalemate and delay. Federal Trade Commission agrees that the lack of rate structures to allocate the costs of needed transmission, and the free rider problem that arises when project beneficiaries seek to shift transmission construction costs onto others, add uncertainty and conflict to the debate over what transmission to build and how to pay for it. Sunflower and Mid-Kansas state that the free rider problem can be an issue regionally, but is likely to prove more intractable for interregional cost allocation. Boundless Energy and Sea Breeze state that cost allocation has to deal with the free rider issue when multiple utilities are involved because then an independent entity with a proposal that provides system benefits across a larger region may find that beneficiaries will not

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*Illinois Commerce Commission*, arguing that the court did not interpret the cost causation principle to require that costs be allocated on a narrow definition of "cause" that ignores benefits received by customers.

[404] *E.g.*, Gaelectric North America; Atlantic Grid; Multiparty Commenters; Primary Power; Pennsylvania PUC; NextEra; Federal Trade Commission; Sunflower and Mid-Kansas; Boundless Energy and Sea Breeze; and LS Power.

contract for their portion of the benefits.

513. Several commenters argue that it is unlawful for transmission developers to recover costs from entities to which they do not provide service.[405] Some commenters contend that the Commission ignores that privity of contract existed between the entities involved in the cases that it cites to support its proposal[406] and that the Commission's authority under the FPA is premised on a utility having a contractual relationship or a tariff to provide service to its customers.[407] Nebraska Public Power District asserts that the *Mobile-Sierra* cases support this view.[408]

514. Sacramento Municipal Utility District asserts that there is a distinction between allocating costs among a public utility transmission provider's customers without their

[405] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Salt River Project; and Sacramento Municipal Utility District.

[406] *E.g.*, Ad Hoc Coalition of Southeastern Utilities (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 144); Salt River Project (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164).

[407] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Salt River; and Nebraska Public Power District.

[408] Nebraska Public Power District (citing *United Gas Pipeline Co. v. Mobile Gas Corp.*, 350 U.S. 332 (1955); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956)).

voluntary agreement (such as the roll-in of the costs of the transmission provider's bulk transmission system) and allocating them to entities that are not the transmission provider's customers. It argues that *AEP* and similar cases[409] do not establish a right to assess costs of facilities to non-customers and that it is a perversion of the statutory scheme to suggest that an entity could build a transmission facility and then claim that because power generated or scheduled by non-customers flowed over the facility, it was entitled to be compensated by them. Southern Companies note that no complaint was filed in response to *AEP*, and the case therefore does not support the idea that allocation of costs to non-customers is lawful. Northern Tier Transmission Group maintains that even if the Commission has authority to permit allocation of costs to an entity that does not take service from the transmission provider that collects the costs, it has not complied with the common law requirements necessary to delegate that authority to transmission providers.

515. Sacramento Municipal Utility District asserts that the cases that the Commission cites dealing with the allocation of costs between RTOs when new facilities in one of their footprints benefits entities in the other's footprint do not apply here.[410] It argues

[409] In addition to *AEP*, Sacramento Municipal Utility District cites *Sierra Pacific Power Co.*, 85 FERC ¶ 61,314 at 62,235 (1998); *Sierra Pacific Power Co.*, 86 FERC ¶ 61,198 at 61,698 (1999); *Vermont Elec. Power Co.*, 44 FERC ¶ 61,098, at 61,275 (1988).

[410] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084;

(continued…)

that in those cases, cross-border facility costs were allocated to each RTO as a whole, after which project costs were recovered by the RTO through its own intra-RTO cost allocation. Sacramento Municipal Utility District states that customers in these cases were not being billed for service taken from entities with which those customers had no

contract or applicable tariff, but rather were being billed by their own transmission providers.

516. Sacramento Municipal Utility District takes issue with the Commission's reliance on *MISO Transmission Owners* for the proposition that the cost causation principle allows allocation of at least some types of costs to beneficiaries that are not customers of the public utility that is seeking cost recovery. It states that in that case, MISO was the public utility seeking cost recovery, and the costs in question were not levied directly on the entities in question. Instead, the MISO transmission owners – existing customers under the MISO tariff – had challenged whether the cost allocation reflected in their rates was reasonable. Sacramento Municipal Utility District contends that all the court decided was that the Commission had reasonably allocated MISO's operating costs to the transmission owners based on their use of MISO-controlled transmission facilities to deliver power to entities that were not subject to the MISO tariff and on the benefits that

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*Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168; *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194.

MISO Transmission Owners derived from that delivery.[411]

517. Sacramento Municipal Utility District asserts that the Commission's position on joint rates supports its position that a contractual customer relationship is a precondition for the allocation of transmission costs. It states that the Commission's position is that, absent evidence that two systems were in fact acting as one, the Commission cannot mandate the use of a single joint rate. Sacramento Municipal Utility District argues that if the Commission cannot mandate joint rates when this condition is not met even where a customer takes service from both utilities, it cannot mandate that an entity pay rates charged by a utility with which it has no contractual or tariff-based customer relationship.[412]

518. ColumbiaGrid argues that the Commission cannot use its authority to force customers to pay for additional benefits that go beyond their existing service. It states that a court has held that under section 5 of the Natural Gas Act, the Commission may

[411] *See also* Southern Companies and ColumbiaGrid.

[412] Sacramento Municipal Utility District cites to *Ft. Pierce Utilities Comm'n v. FERC*, 730 F.2d 778 (D. C. Cir. 1984) (*Fort Pierce*); *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) ("purchasers are always free to subscribe to the services of willing utilities at the separate rates"); *Alabama Power Co. v. FERC*, 993 F.2d 1557, 1565 (D. C. Cir. 1993) (affirming order directing joint rate between holding company members who the Commission found were acting as one); *see also Illinois Power Co.*, 95 FERC ¶ 61,183, at 61,644 (2002) (approving single joint rate across Alliant and MISO systems but recognizing that, in the absence of an agreement between these utilities, there would not be a single rate).

reject unjust and unreasonable rates and prescribe a new just and reasonable rate, but it may not require distributors to accept or to pay for additional service.[413] ColumbiaGrid maintains that this shows that costs cannot be recovered from entities that are not customers receiving jurisdictional service. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the allocation of costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries, and it maintains that the Commission's reliance on this case to extend the cost causation principle to cover any entity that may be said to benefit from a project is misplaced.

519. Southern Companies argue that while the Proposed Rule acknowledges the fundamental role of cost causation, it proceeds to nullify the "but for" element that is intrinsic to any determination of cost causation. Southern Companies argue that the primary beneficiary of a transmission improvement is the customer that made the request that "causes" the improvement in question. They argue that the Proposed Rule seems to attack cost causation by concluding that a participant funding approach is not permissible.

520. Several commenters maintain that in their experience, free rider problems do not exist and that such concerns may be speculative.[414] Ad Hoc Coalition of Southeastern

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[413] ColumbiaGrid cites to *Exxon Mobil Corp. v. FERC*, 430 F.3d 1166 (D.C. Cir. 2005) (*Exxon Mobil Corp.*).

[414] *E.g.*, Southern Companies; California Municipal Utilities; Transmission

(continued…)

Utilities states that cost socialization is not needed to protect against the inequities of free ridership. It interprets the Commission's reference to the free rider problem as referring to the relatively cost-free transmission that may be provided to entities that take advantage of oversized investments made by others.

521. Southern Companies suggest that if any such problems exist, they are a product of local or regional factors that do not require a national solution. E.ON argues that free rider problems do not exist in the context of reliability or public policy transmission projects, and participant funding of such projects does not exacerbate the free rider problem.

522. Some commenters argue that, even if free rider problems exist, they can either be solved without resort to broad cost allocation or are beyond the Commission's authority.[415] Alternatively, Illinois Commerce Commission states that while a free rider problem does exist, it is impossible to solve in practice, and the negative consequences of allocating costs too broadly will be greater than allocating costs more narrowly to cost causers and direct, quantifiable beneficiaries. Dominion similarly asserts that while broad cost allocation may eliminate free ridership, it may result in some entities paying

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Agency of Northern California; and Columbia Grid.

[415] *E.g.*, Nebraska Public Power District and Sacramento Municipal Utility District.

disproportionate costs.

523. Alabama PSC states that it would be improper to require citizens of Alabama to pay for the costs of transmission facilities in other areas of the country where there is high congestion and which are not necessary to provide service in Alabama. It maintains that this violates the principle of cost causation and the requirement that facilities be "used and useful" before being incorporated into a consumer's rates. Indianapolis Power & Light argues that it is inconsistent with cost causation principles to subsidize a state's generation decisions (e.g., a state's renewable portfolio standard), and states should not be able to pass the cost of compliance with their requirements on to other jurisdictions. ELCON agrees and states that a claim of generalized system benefits, such as an amorphous reliability improvement, does not justify regionalized charges. Instead, ELCON asserts that there must be a tangible, nontrivial benefit supported by substantial evidence. ELCON also maintains that disallowing export charges or other forms of cost transfer to beneficiaries in other planning regions will result in unjust and discriminatory rates.

524. Coalition for Fair Transmission Policy states that the Commission lacks authority to require consideration of broad public policy benefits that cannot be measured or projected within a transmission providers' planning horizon. It maintains that allowing the allocation of costs that are not required to maintain reliability, relieve congestion, or to meet mandated public policy requirements is beyond the Commission's core mission.

525. Ad Hoc Coalition of Southeastern Utilities states that in the Southeast, only North Carolina has a renewable portfolio standards requirement, and there is no suggestion that a regional mechanism for funding transmission is needed to satisfy this requirement. It thus sees no reason to discontinue providing cost recovery for regional transmission projects from the entities that choose to use them.

526. ColumbiaGrid argues that at least with respect to non-RTO regions (where there are no regional service tariff rates), directing public and non-public utilities to adopt a specific cost allocation method in advance could infringe upon a utility's right to propose rates under section 205 of the FPA.[416] The California ISO maintains that the Commission does not have the authority to compel rate filings in the first instance, and it can require a filing only if it shows that the existing rate does not meet the requirements of section 206.[417] California ISO argues that the Commission cannot fulfill this requirement with regard to cost allocation for regional and interregional facilities because there are no existing contracts or rates for such services. The Commission may at most issue guidance on whether future filings will meet statutory requirements.

527. Southern Companies assert that where vertically integrated transmission providers

[416] ColumbiaGrid bases this claim on *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City*).

[417] Similarly, Northern Tier Transmission Group argues that the Commission must justify, under section 206, modifying the cost allocation process that it already accepted for its members.

plan their transmission systems from the bottom up under state supervision and recover most of their costs for transmission facilities through bundled rates, the Proposed Rule's mandates cannot be implemented without preempting or undermining state law. Southern Companies state that the Commission should revise its proposed reforms and explain how they can be implemented while respecting existing processes for bundled retail ratemaking. Southern Companies assert that they recover only approximately 15 percent of their transmission revenue requirements under a federal OATT, with the remaining 85 percent being recovered in state-regulated bundled rates. They state that the latter cost recovery is not an issue of federal comparability, and a nonincumbent would, at best, be allowed to recover only 15 percent of its transmission costs under a federal OATT, with the rest requiring state approval. Southern Companies maintain that as a practical matter, a nonincumbent cannot have "comparable" cost recovery without a long-term contract from Southern Companies that has appropriate state commission approval for purposes of retail rate recovery.

528. Transmission Access Policy Study Group urges the Commission to address allocation of costs of transmission projects that go beyond existing boundaries of an RTO or individual transmission providers where the transmission grid is integrated. It recommends that the Commission recognize that it has the authority to order joint, non-pancaked rates where transmission systems are integrated. Sacramento Municipal Utility District argues in response that the Commission cannot require joint rates unless two

adjoining transmission systems are not just integrated, but effectively operate as a single system. Large Public Power Council agrees. Ad Hoc Coalition of Southeastern Utilities argues that the statutory right of utilities to set their rates may not be easily set aside, and that imposing a joint, non-pancaked rate structure on utilities would do exactly that.

529. Florida PSC is concerned that the Commission's proposal may circumvent its authority over rates for transmission infrastructure that serves retail load because the Proposed Rule appears to allow entities seeking to construct merchant transmission projects to recover project costs from Florida ratepayers through a Commission-approved cost allocation process. North Carolina Agencies argue that the Final Rule should recognize the indispensible role of state regulatory authorities and should apply only to unbundled transmission rates. Northwestern Corporation (Montana) states that entities seeking to recover costs without approval from state public utilities commissions face the risk of cost disallowance.

### 3. Commission Determination

530. We conclude that we have the legal authority to adopt the cost allocation reforms required by this Final Rule. Numerous commenters challenge our authority to require allocation of transmission costs to beneficiaries that do not have a contractual or formalized customer relationship with the entity that is collecting the costs. These challenges are based primarily on the commenters' analysis of various Commission and court cases. Some commenters have made arguments that speak directly to provisions of

the FPA, but none of these assertions reach convincing conclusions. For instance, Ad Hoc Coalition of Southeastern Utilities states that "[u]tilities filing for rate changes under FPA section 205 ask the Commission to approve changes in rates charged *to their customers*" and that "the Commission's authority is, in all cases, based on the premise that a utility has a contractual relationship to provide service to its customers."[418] However, section 205 does not specify any such limitation and no commenter has shown where it is expressed elsewhere in the FPA. Instead, commenters generally appear to agree with Ad Hoc Coalition of Southeastern Utilities that the "FPA is structured on the *assumption* that rates subject to [Commission] approval are supported by a contractual agreement."[419]

531. The merit of this argument depends, of course, on how the FPA is in fact structured, and an examination of the relevant provisions of the statute shows that it is not structured in a way that would justify this argument. On the contrary, the Commission's jurisdiction is clearly broad enough to allow it to ensure that all beneficiaries of services provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. As discussed further below, this comports fully with the specific characteristics of

[418] Ad Hoc Coalition of Southeastern Utilities Comments at 60-61 (emphasis in original).

[419] *Id.* at 60 (emphasis supplied).

transmission facilities and transmission services, and our actions today are necessary to fulfill our statutory duty of ensuring rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. We thus turn first to the language of the statute itself.

532. Section 201(b)(1) of the FPA gives the Commission jurisdiction over "the transmission of electric energy in interstate commerce." The Commission's jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements. Moreover, section 201(b)(1) gives the Commission jurisdiction over "all facilities" for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions. As a result, the Commission has jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities.

533. Neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. These statutory provisions speak of rates and charges that are "made," "demanded," "received," "observed," "charged," or "collected" by a public utility. Any such rates or charges must, of course, be accepted for

filing with the Commission under either section 205 or 206, but nothing in these sections precludes flows of funds to public utility transmission providers through mechanisms other than agreements between the service provider and the beneficiaries of those transmission facilities.

534. Transmission services create an opportunity for free ridership because the nature of power flows over an interconnected transmission system does not permit a public utility transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them. The Commission expressed concern over free ridership in Order No. 890, where it noted that "there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it."[420]

535. In Order No. 890, the Commission recognized that the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them. We conclude now that this principle cannot be limited to voluntary arrangements because if it were "the Commission could not address free rider problems associated with new transmission investment, and it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory. In fact, the courts have recognized this aspect of cost causation

[420] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 561.

quite independently of an analysis of the scope of our statutory jurisdiction over transmission.

536. The courts have acknowledged that cost causation involves "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[421] An approach to cost causation that is limited to voluntary arrangements such as participant funding has the effect of "focusing us on the most immediate and proximate cause of the cost incurred," and it precludes looking "at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign[ing] them liability too."[422] In short, a full cost causation analysis may involve "an extension of the chain of causation"[423] beyond those causes captured in voluntary arrangements. In other words, to identify all causes, we must to some degree begin with their effects, i.e., the benefits that they engender and then work back to their sources.

537. This point was acknowledged in the Seventh Circuit's characterization of cost causation in *Illinois Commerce Commission*. The Seventh Circuit states that:

> To the extent that a utility benefits from the costs of new facilities, *it may be said to have "caused" a part of those costs to be incurred*, as without

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[421] *MISO Transmission Owners*, 373 F.3d 1361, at 1368 (internal citations omitted).

[422] *KN Energy*, 968 F.2d 1295 at 1302.

[423] *Id.*

> the expectation of its contributions the facilities might not have been built, or might have been delayed.[424]

The court fully recognized that, to identify causes of costs, one must to some degree begin with benefits. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the Commission's position on cost allocation because the statement just cited is preceded by the statement that "[A]ll *approved* rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[425] ColumbiaGrid maintains that this demonstrates the *Illinois Commerce Commission* "does not support the [Proposed Rule's] approach of allocating costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries."[426] What this argument fails to recognize is that the point ColumbiaGrid contests was not before the court in *Illinois Commerce Commission*, and the Commission's jurisdiction over transmission, as outlined above, is broad enough to approve rates based on the court's characterization of cost causation.[427] In other words, there is nothing in what the

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[424] *Illinois Commerce Commission*, 576 F.3d 470 at 476 (emphasis supplied).

[425] ColumbiaGrid Comments at 29 (citing *Illinois Commerce Commission*, 576 F.3d 470 at 476 (emphasis supplied by ColumbiaGrid)).

[426] *Id*.

[427] This point applies equally to Sacramento Municipal Utility District's objection that the other Commission and court cases pertaining to MISO cited in the Proposed Rule are not on point because they involve instances where a customer relationship of some type had already been established, and that all that these cases dealt with was whether an allocation was just and reasonable. When Sacramento Municipal Utility District states

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court said that can be viewed as preventing the Commission from dealing with the free rider problem. Indeed, by emphasizing the relationship between beneficiaries identified and cost allocation, the court's ruling supports greater attention to that issue. Finally, we note that under this Final Rule, transmission planning regions are not required to analyze the distribution of benefits on an entity-by-entity basis; nothing in this Final Rule precludes the regions from doing so, provided that they satisfy the cost allocation

principles adopted herein. We now turn to other individual comments that involve these issues.

538. Southern Companies' argument that the primary beneficiary of a transmission facility is the customer that made the request that causes the improvements to be planned and constructed tends to blur the distinction between benefits and burdens. As discussed above, the courts have acknowledged that distinction as relevant to cost allocation and the requirements in this Final Rule are consistent with that distinction. To the extent that

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that "the cost allocation methods approved by FERC in the MISO cases rested on the understanding that 'the ultimate costs allocated to [MISO] or PJM for a so-called cross-border allocation project will be recovered by each RTO pursuant to the applicable provisions of their tariffs,'" it is ignoring substance in favor of form. It is focusing on the formal mechanisms through which costs are collected, not the underlying substance of the cost allocation itself. *See* Sacramento Municipal Utility District Comments at 14 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194 at P 4 ). The mechanism for recovering a rate does not change the identity of the provider who is in fact recovering it.

commenters are supporting participant funding as a regional cost allocation method, we address those comments below.[428]

539. We disagree with Sacramento Municipal Utility District and Southern Companies that *AEP* applies only in exceptional circumstances and does not support our position here. In that case, the Commission expressed a preference for a voluntary resolution of the problem that loop flow represented, a position that is consistent with our findings here. The Commission's authority is not limited in principle by cases where the Commission expresses a preference not to exercise that authority. We also disagree with Sacramento Municipal Utility District that our reforms represent a perversion of the statutory scheme in which an entity could build a transmission facility and then simply claim a right to payment for benefits from beneficiaries with which it has no contractual or tariff relationship. As we state above, the Commission's jurisdiction is broad enough to allow it to ensure that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. Our cost allocation reforms are tied to our transmission planning reforms, which require that, to be eligible for regional cost allocation, a proposed new transmission facility first must be selected in a regional transmission plan for purposes of cost allocation, which depends on a full assessment by

[428] *See* discussion *infra* section IV.F.2.

a broad range of regional stakeholders of the benefits accruing from transmission facilities planned according to the reformed transmission planning processes. As such, the public utility transmission providers in the regional transmission planning process identify the beneficiaries who will pay for the costs of the new transmission facility selected in a regional plan for purposes of cost allocation.

540. The fact that the Commission has supported parts of its argument through reference to cases in which privity of contract existed between public utilities and the entities from which costs were recovered does not affect this conclusion. [429] This issue was not before the court in any of these cases, and therefore the mere existence of privity of contract does not demonstrate the necessity of privity. In response to Nebraska Public Power District, we do not agree that the *Mobile-Sierra* doctrine has applicability here. We are dealing here with conditions under which costs can be recovered in rates, not conditions under which existing contracts rates can be altered.

541. Contrary to ColumbiaGrid's position, *Exxon Mobil Corp.* does not apply here. As ColumbiaGrid states, in *Exxon Mobil Corp.* the court held that the Commission may not require distributors to accept or pay for additional service. [430] Unlike the situation addressed in *Exxon Mobil Corp.*, the requirements of this Final Rule with respect to cost

[429] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168; *Alliance Cos.*, 100 FERC ¶ 61,137.

[430] *See Exxon Mobil Corp.*, 430 F.3d 1166, 1176-77 (D.C. Cir. 2005).

allocation do not "impose" any new service on beneficiaries.

542. We also note that our position on joint rates does not have any relevance here. The fact that the Commission cannot require two public utilities to charge a joint rate without evidence that their two systems are in fact acting as one does not preclude the Commission from permitting a single public utility to recover its costs from beneficiaries of the transmission facilities identified in the transmission planning process regardless of the formal customer relationships that exist prior to the time that cost allocation is authorized. We do not see how the conditions under which a joint rate can be imposed has any implications for the range of beneficiaries from which a single public utility can recover the costs of its transmission services, even when combined with recovery by other public utilities of related transmission facilities.

543. We disagree with Northern Tier Transmission Group that we are delegating any authority to transmission providers. All proposed cost allocation methods will be subject to Commission approval, and all specific allocations will be incorporated in rates that must be filed with and accepted by the Commission.

544. We agree with the Alabama PSC that citizens of Alabama should not be responsible for costs of transmission facilities from which they derive no benefits. Indeed, the Commission specified in the Proposed Rule as a principle of regional cost allocation that "[t]hose that receive no benefit from transmission facilities, either at

present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities."[431] With respect to interregional transmission coordination, the Commission specified that a "transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility."[432] In addition, "[c]osts cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located."[433] These cost allocation principles are adopted in this Final Rule, and its requirements thus conform fully with the position taken by the Alabama PSC.

545. Contrary to the claims of Indianapolis Power & Light, the reforms instituted in this Final Rule neither authorize nor will lead to subsidization of generation decisions by different states. Beneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state's transmission needs driven by Public Policy Requirements. If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits

[431] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

[432] *Id.* P 174.

[433] *Id.*

because Public Policy Requirements played a role in the decision to construct the transmission facility. We agree with ELCON that estimations of benefits require adequate support. We note, however, that benefits are not "amorphous" simply because costs are to be allocated "in a manner that is roughly commensurate with estimated benefits."[434] The courts have acknowledged the natural limits that accompany estimations made in the cost-allocation process.[435]

546. We disagree with Coalition for Fair Transmission Policy that the Proposed Rule can be read to imply that the Commission may require consideration of broad policy goals that are far afield from the Commission's core mission. This Final Rule requires that public utility transmission providers establish a process for identifying those transmission needs driven by Public Policy Requirements that are to be considered in the transmission planning process.[436] In doing this, we are simply acknowledging that such Public Policy Requirements are facts that may have consequences in the form of increasing or decreasing the demand for additional transmission facilities. We are not

[434] The Commission discusses in detail the application of this cost allocation principle below.

[435] *Illinois Commerce Commission*, 576 F.3d 470 at 476-77 ("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars."). *See also MISO Transmission Owners*, 373 F.3d 1361 at 1369 ("we have never required a ratemaking agency to allocate costs with exacting precision."); *Sithe*, 285 F.3d 1 at 5.

[436] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 4.

straying from our core mission when we acknowledge that these facts will affect matters that are central to that mission and accordingly require that they be considered in the transmission planning process, nor are we promoting any particular public policy by requiring a process to determine what, if any, transmission needs are driven by a Public Policy Requirement.[437]

547. Directing a public utility transmission provider to adopt a specific cost allocation method or methods in advance does not infringe upon a utility's right to propose rates under section 205 of the FPA. It simply requires that rate filings meet certain standards. ColumbiaGrid cites *Atlantic City* as supporting the contrary position. In that case, the court held that the Commission could not require that the PJM Transmission Owners Agreement be modified to eliminate a provision that allowed a public utility transmission owner to make a unilateral filing to make changes in rate design or terms and conditions of jurisdictional services. The court held that public utilities have an express right under section 205 to make such filings, and the Commission could not require them to relinquish it.[438] Nothing in this Final Rule has the effect of disenfranchising any individual or entity of rights under section 205 to make filings. The Commission regularly establishes standards for filings under section 205, and doing so does not negate

[437] *See* discussion *supra* section III.A.4.

[438] *Atlantic City*, 295 F.3d 16, at 21 (D.C. Cir. 2002).

any rights under that section.

548. In response to those commenters that argue that our cost allocation reforms will affect existing state jurisdiction over utility rates, it is not clear why cost allocations consistent with this Final Rule would affect state jurisdiction differently from existing cost allocations. In any event, we find that such arguments are premature. It is inappropriate for the Commission to decide such issues generically in a rulemaking, as such issues should be decided based on specific facts and circumstances, none of which are presented here.

549. In response to Transmission Access Policy Study Group, we note that the issue of joint rates is beyond the scope of this proceeding. This Final Rule requires the development of cost allocation methods for regional and interregional transmission facilities in connection with its planning reforms. As described in the cases that commenters cite in their responses to Transmission Access Policy Study Group, the issue of joint, non-pancaked rates involves matters that are considerably broader than our transmission planning-based cost allocation reforms. The Commission will consider any

calls for joint, non-pancaked rates on a case-by-case basis and in accordance with the principles established in these cases.

### C. Cost Allocation Method for Regional Transmission Facilities

#### 1. Commission Proposal

550. The Proposed Rule would require that every public utility transmission provider develop a method, or set of methods, for allocating the costs of new transmission facilities that are included in the transmission plan produced by the transmission planning process in which it participates. If the public utility transmission provider is an RTO or ISO, then the method or methods would be required to be set forth in the RTO or ISO tariff. In other transmission planning regions, each public utility transmission provider would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region. This method or methods would have to satisfy six regional cost allocation principles, discussed below.

551. These regional cost allocation principles would apply only to the cost allocation method or methods for new transmission facilities selected in the regional transmission plan produced by the transmission planning process in which the public utility transmission provider participates. The Commission also stated that it did not intend to require a uniform cost allocation method that every region must adopt to allocate the costs of new regional transmission facilities that are eligible for cost allocation, but

instead recognized that regional differences may warrant distinctions in cost allocation

methods among transmission planning regions.[439]

552. The Commission stated in the Proposed Rule that with regard to a new transmission facility that is located entirely within one transmission owner's service territory, a transmission owner may not unilaterally invoke the regional cost allocation method to require the allocation of the costs of a new transmission facility to other entities in its transmission planning region. However, if the regional transmission planning process determines that a new facility located solely within a transmission owner's service territory would provide benefits to others in the region, allocating the facility's costs according to that region's regional cost allocation method or methods would be permitted.[440]

### 2. Comments on Cost Allocation Method in Regional Transmission Planning

553. A number of commenters generally support the Commission's proposal.[441] For example, ITC Companies support the promulgation of a comprehensive, holistic cost

[439] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 165.

[440] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 169.

[441] *E.g.*, MidAmerican; American Transmission; Clean Line; Dominion; East Texas Cooperatives; MISO; National Grid; NEPOOL; New York ISO; Multiparty Commenters; and WIRES.

allocation method generally applicable to new transmission facilities, citing SPP's highway/byway mechanism as a model.[442]

554. Other commenters express concern with the Commission's proposal to require the development of a cost allocation method for transmission facilities included in a regional transmission plan.[443] Bonneville Power asserts that mandatory regional cost allocation is not necessary to build new transmission in the Pacific Northwest, and such a requirement will lead to extended disputes and greater uncertainty. Bonneville Power contends that instead, voluntary participation, including participation in open seasons, is the best way to encourage the development of new transmission for renewables in the Pacific Northwest. California Commissions echo the sentiment that cost allocation has generally not been a major barrier to entry for new transmission in the West. California Commissions are concerned that the Commission may do more harm than good by moving aggressively and prescriptively on regional cost allocation methods that are not necessarily needed to support transmission development.

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[442] The arguments in support of this proposal are implicit in the comment summaries under the discussion of other cost allocation proposals below. *See* discussion *infra* section IV.E.8. The term "highway/byway" refers to regionwide allocation of the cost of a new high voltage transmission facility and the allocation of the cost of a new lower voltage transmission facility to a defined portion of the region. *See Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010).

[443] *E.g.*, Bonneville Power Administration; California Commissions; Eastern Massachusetts Consumer-Owned System; Xcel; and Western Area Power Administration.

555. Some commenters, such as Bonneville Power, California ISO, and Western Area Power Administration, express a preference for voluntary coordination and cost allocation of transmission facilities rather than mandatory cost allocation rules. Coalition for Fair Transmission Policy urges the Commission to consider whether it is prudent in all cases to require the filing of regional cost allocation methods by transmission providers in advance of projects being proposed, as not every project will fit into a particular model, and adherence to strict rules may deter rather than encourage the construction of needed new transmission facilities.

556. New York PSC indicates that it is uncertain as to whether the Commission intends to utilize a pre-established cost allocation methodology as an automatic right of cost recovery. Therefore, New York PSC requests that the Commission clearly indicate when a project would be entitled to cost recovery relative to receiving a cost allocation. Western Grid Group shares the view that the distinction between cost allocation and cost recovery is a pertinent issue. Arizona Public Service Company raises concerns about cost recovery in regions where no regional tariff mechanisms exist. In the absence of such a cost recovery solution, Arizona Public Service Company states that the Commission should not place the burden of recovery for third party developers on incumbent utilities that may be required to seek such recovery through state commissions for facilities that the incumbent utilities have not built and for which the incumbent utilities may be unable

to show benefit for their ratepayers.

557. MISO Transmission Owners agree that a transmission provider should not be able to invoke the regional cost allocation method unilaterally for a facility located entirely within its own service territory. However, they state that in the RTO context, facilities located solely within one transmission owner's service territory should be allocated in accordance with the Commission-accepted cost allocation method. MISO Transmission Owners state that the Proposed Rule should not be interpreted to indicate that single-zone facilities are no longer eligible for regional cost allocation if such allocation is permitted under an RTO or ISO tariff. Additionally, MISO Transmission Owners argue that the Commission should not permit this requirement to allow attempts to relitigate existing cost allocation method that apply to intra-zonal transmission facilities.

### 3. Commission Determination

558. We require that a public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. If the public utility transmission provider is an RTO or ISO, then the cost allocation method or methods must be set forth in the RTO or ISO OATT. In a non-RTO/ISO transmission planning region, each public utility transmission provider located within the region must set forth in its OATT the same language regarding the cost allocation method or methods used in its

transmission planning region. In either instance, such cost allocation method or methods must be consistent with the regional cost allocation principles adopted below.

559. We conclude that these regional transmission cost allocation requirements are necessary to ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. In the absence of clear cost allocation rules for regional transmission facilities, there is a greater potential that public utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs. Conversely, greater certainty as to the cost allocation implications of a potential transmission project will enhance the ability of stakeholders in the regional transmission planning process to evaluate the merits of the transmission project. Moreover, as we have established above, there is a fundamental link between cost allocation and planning, as it is through the planning process that benefits, which are central to cost allocation, can be assessed.

560. We do not specify here how the costs of an individual regional transmission facility should be allocated. However, while each transmission planning region may develop a method or methods for different types of transmission projects, such method or methods should apply to all transmission facilities of the type in question. Although we allow a different method or methods for different types of transmission facilities, as discussed below regarding regional Cost Allocation Principle 6, if public utility

transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each method would have to be determined in advance for each type of facility.

561. We disagree with California Commissions that our actions here are too aggressive and prescriptive and with Bonneville Power that adopting a mandatory cost allocation method will lead to extended disputes and greater uncertainty. We have stressed throughout this proceeding that we intend to be flexible and are open to a variety of approaches to compliance. By imposing the cost allocation requirements adopted here, the Commission seeks to enhance certainty for developers of potential transmission facilities by identifying, up front, the cost allocation implications of selecting a transmission facility in the regional transmission plan for purposes of cost allocation. This does not undermine the ability of market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or methods. Indeed, market participants may be in a better position to undertake such negotiations as a result of the public utility transmission providers in the region having evaluated a transmission project. The results of that evaluation, including the identification of potential beneficiaries of the transmission project, could facilitate negotiations among potentially interested parties.

562. In response to Coalition for Fair Transmission Policy, we require the development of a cost allocation method or a set of methods in advance of particular transmission

facilities being proposed so that developers have greater certainty about cost allocation and other stakeholders will understand the cost impacts of the transmission facilities proposed for cost allocation in transmission planning. The appropriate place for this consideration is the regional transmission planning process because addressing these issues through the regional transmission planning process will increase the likelihood that transmission facilities selected in regional transmission plans for purposes of cost allocation are actually constructed, rather than later encountering cost allocation disputes that prevent their construction.

563. With regard to comments regarding matters of cost recovery, we acknowledge that cost allocation and cost recovery are distinct. This Final Rule sets forth the Commission's requirements regarding the development of regional and interregional cost allocation methods and does not address matters of cost recovery. We disagree with Arizona Public Service Company, however that incumbent utilities may be unreasonably burdened by the potential of cost allocation for transmission facilities developed by third party developers. For any proponent of a transmission facility, whether an incumbent or a nonincumbent, to have the costs of a transmission facility allocated through the regional cost allocation method or methods, its transmission facility first must be selected in the regional transmission plan for purposes of cost allocation. This in turn requires a determination that the transmission project is an efficient or cost-effective solution pursuant to the processes the transmission providers in the region have put in place,

including consultation with stakeholders. Therefore, the benefits of any such transmission project should have been clearly identified prior to the allocation of any related costs.

564. With respect to cost allocation for a proposed transmission facility located entirely within one public utility transmission owner's service territory, we find that a public utility transmission owner may not unilaterally apply the regional cost allocation method or methods developed pursuant to this Final Rule. However, a proposed transmission facility located entirely within a public utility transmission owner's service territory could be determined by public utility transmission providers in the region to provide benefits to others in the region and thus the cost of that transmission facility could be allocated according to that region's regional cost allocation method or methods.

565. In response to MISO Transmission Owners' concerns regarding relitigation of existing Commission-approved transmission cost allocation methods, the Commission declines here to prejudge whether any such existing cost allocation methods comply with the requirements of this Final Rule. To the extent MISO Transmission Owners believe that to be the case with their region, they may take such positions during the development of compliance proposals and during Commission review of compliance filings. However, we reiterate here that our cost allocation reforms apply only to new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and, therefore, do not provide grounds for relitigation of cost allocation

decisions for existing transmission facilities.

### D. Cost Allocation Method for Interregional Transmission Facilities

#### 1. Commission Proposal

566. The Proposed Rule would require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new interregional transmission facility between the two neighboring transmission planning regions in which the facility is located or among the beneficiaries in the two neighboring transmission planning regions. This common method would have to satisfy six interregional cost allocation principles, discussed below.

567. The Commission stated in the Proposed Rule that it would not apply the interregional cost allocation principles so as to require every pair of regions to adopt the same uniform approach to cost allocation for new interregional transmission facilities, but instead recognized that there may be legitimate reasons for the public utility transmission providers located in different pairs of neighboring transmission planning regions to adopt different cost allocation methods.[444]

#### 2. Comments on Interregional Cost Allocation Reforms

568. A number of commenters generally support the proposal that each transmission provider have an interregional cost allocation method for facilities located in more than

[444] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 175.

one region.[445] NEPOOL states that it generally supports the proposal to require formal agreements between neighboring control areas that contain cost allocation methods for interregional projects, with such methods being subject to the principles specified in the Proposed Rule. East Texas Cooperatives support the application of the six proposed principles to interregional cost allocation methods. AEP states that getting these ground rules in place is essential to move forward on major interregional projects and to break down decades old barriers to these types of projects. Likewise, MidAmerican states that there is little if any coordination of transmission cost allocation between MISO and SPP regions and the MISO and MAPP regions and, as such, supports the Commission's efforts to create a more coordinated and effective way to allocate costs of new transmission facilities both within these planning regions and those linking adjacent planning regions.

569. Vermont Electric states that it welcomes the proposed requirement for interregional coordination and the Commission's attention to what it views as deficiencies in the ISO New England transmission planning process. Vermont Electric states that the Commission's proposed requirement for a standard cost allocation method applicable to interregional projects would prevent delays, reduce costs for project

[445] *E.g.*, AEP; Clean Line; MidAmerican; MISO; MISO Transmission Owners; NEPOOL; New England States Committee on Electricity; Northeast Utilities; Pennsylvania PUC; PSEG Companies; and Energy Consulting Group.

developers, and facilitate development of potentially valuable interregional projects.

570. A number of commenters question or express concern about the appropriateness of requiring the development of interregional cost allocation methods for future interregional transmission facilities in advance of a proposal for a specific interregional facility.[446] For example, SoCal Edison notes that voluntary coordination efforts are underway, and it argues that there is no reason to impose additional mandatory interregional coordination criteria or requirements. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. ISO New England also states that the Final Rule should either clarify the manner in which agreement on cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

571. National Grid believes that interregional coordination agreements should include general cost allocation principles that will apply to interregional projects, but that it would not be beneficial to prescribe an interregional cost allocation method in advance of a specific interregional project. Similarly, New England Transmission Owners and New York Transmission Owners contend that, in light of the limited number of projects that

[446] *E.g.*, New York ISO; Coalition for Fair Transmission Policy; California ISO; and National Grid.

are likely to be identified through interregional coordination, the Commission should allow cost allocation issues to be decided in connection with individual projects instead of dictating a generic cost allocation method in advance.

572. Vermont Electric agrees, suggesting that the Commission impose an interregional requirement only to the extent regional planning organizations do not respond promptly and effectively to cost allocation issues applicable to interregional projects on a case-by-case basis. New York ISO recommends that the Commission require neighboring regions to include language in their tariffs setting forth their obligation to negotiate cost allocation rules for any interregional projects that are approved in their respective planning processes and that such rules must comply with the cost allocation principles established in the Final Rule.

573. Similarly, Transmission Agency of Northern California cautions against requiring the development of cost allocation principles between planning regions prior to the need for such coordination. California ISO and Indianapolis Power & Light also argue that the requirement for a mandatory advanced agreement on cost allocation before knowing the specific facts and circumstances of an interregional project is neither appropriate nor effective. Indianapolis Power & Light also states that it would be better to postpone development of such agreements until a specific interregional project has been proposed.

574. California ISO states that the Commission should not mandate an interregional cost allocation method or methods because the existing case-by-case determination of

cost allocation for interregional transmission facilities has worked well in the West. California ISO states that different parties will bring different interests to the table, and different circumstances may warrant different approaches to interregional cost allocation. However, California ISO states that regardless of what the Commission concludes on this issue, it should retain in the Final Rule the concept that inclusion of an interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to applying an interregional cost allocation principle.[447] California ISO argues that this is necessary to ensure equitable cost allocation.

575. Edison Electric Institute states that flexibility is especially important for multistate projects with a large number of likely beneficiaries. It states that flexibility also is important for different regions in developing interregional cost allocation methods, including methods that provide for a case-by-case evaluation of projects in lieu of using prescribed cost allocation formulas. Edison Electric Institute states that the Commission should allow a region to propose the evaluation of alternative cost-effective projects that would result in lower costs to the region's consumers.

576. Edison Electric Institute also asks the Commission to be clear in the Final Rule about whether and how existing interregional cost allocation mechanisms and those under development in various regions will be affected, if at all. Transmission Dependent Utility

[447] *See also*, *e.g.*, Connecticut & Rhode Island Commissions.

Systems and Xcel support the proposed requirement, but request that the Commission not disrupt or disturb the methods already in place. New England Transmission Owners state that the Commission should permit New England and New York to move forward to develop coordinated interregional coordination based on the principles in their current agreement.

577. SPP seeks clarification, consistent with Order No. 890, that transmission owning members of RTOs and ISOs can comply with the proposed interregional cost allocation mandates through their participation in the RTO or ISO and the interregional agreements executed by the RTO or ISO, rather than requiring them to negotiate with their neighbors to develop separate arrangements.

### 3. Commission Determination

578. We require a public utility transmission provider in a transmission planning region to have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located. [448] As we discuss further below, the

[448] A group of three or more transmission planning regions within an interconnection —or all of the transmission planning regions within an interconnection— may agree on and file a common method or methods for allocating the costs of a new

(continued…)

cost allocation method or methods used by the pair of neighboring transmission regions can differ from the cost allocation method or methods used by each region to allocate the cost of a new interregional transmission facility within that region. For example, region A and region B could have a cost allocation method for the allocation of the costs of an interregional transmission facility between regions A and B (the interregional cost allocation method) that could differ from the respective regional cost allocation method that either region A or region B uses to further allocate its share of the costs of an interregional transmission facility. In an RTO or ISO region, the method must be filed in the OATT. In a non-RTO/ISO transmission planning region, the common cost allocation method or methods must be filed in the OATT of each public utility transmission provider in the transmission planning region. In either instance, such cost allocation method or methods must be consistent with the interregional cost allocation principles adopted below.

579. As with our regional cost allocation requirements above, we are requiring interregional cost allocation requirements to remove impediments to the development of transmission facilities that are identified as needed by the relevant regions. We conclude that the absence of clear cost allocation rules for interregional transmission facilities can

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interregional transmission facility. However, the Commission does not require such multiregional provisions among more than two neighboring transmission planning regions.

impede the development of such transmission facilities due to the uncertainty regarding the allocation of responsibility for associated costs. This may, in turn, adversely affect rates for jurisdictional services, causing them to become unjust and unreasonable or unduly discriminatory or preferential.

580. As in the case of regional cost allocation, we do not require a single nationwide approach to interregional cost allocation but instead allow each pair of neighboring regions the flexibility to develop its own cost allocation method or methods consistent with the interregional cost allocation principles adopted in this Final Rule. We also clarify that we do not require each transmission planning region to have the same interregional cost allocation method or methods with each of its neighbors. Each pair of transmission planning regions may develop its own approach to interregional cost allocation that satisfies both transmission planning regions' needs and concerns, as long as that approach satisfies the interregional cost allocation principles. Our intention is to preserve the ability of each pair of transmission planning regions to plan for future development of interregional transmission projects that will be beneficial to both transmission planning regions.

581. We do not specify here how the costs for an individual interregional transmission facility should be allocated. However, while transmission planning regions can develop a different cost allocation method or methods for different types of transmission projects, such a cost allocation method or methods should apply to all transmission facilities of the

type in question. Although we allow a different cost allocation method or methods for different types of transmission facilities, as discussed below regarding Interregional Cost Allocation Principle 6, if public utility transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each cost allocation method would have to be determined in advance for each type of transmission facility. Also, we adopt the requirement that an interregional transmission facility must be in the relevant regional transmission plans to be eligible for interregional cost allocation pursuant to the interregional cost allocation method or methods.

582. Additionally, a central underpinning to our reforms in this Final Rule is the closer alignment of transmission planning and cost allocation. As we discuss above in the section on interregional transmission coordination,[449] an interregional transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to a cost allocation method required under this Final Rule. This is designed, among other things, to allow for adequate stakeholder review of the interregional transmission facility before the relevant portion of the facility is in a regional transmission plan.[450] This process could be undermined if a transmission facility that is

[449] *See* discussion *supra* section III.C.

[450] *See* discussion *supra* section III.C.

located and reviewed only within one regional transmission planning process, could nevertheless have its costs allocated to potential beneficiaries in another region that may not have had an adequate opportunity to review the need for the transmission facility and make the resulting beneficiary determinations. As we make clear in our discussion of Cost Allocation Principle 4,[451] costs may be assigned on a voluntary basis under this Final Rule to a transmission planning region in which an interregional transmission facility is not located. Given this option, regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.

583. With respect to existing interregional transmission coordination and cost allocation agreements, we do not opine here on whether such agreements satisfy the interregional transmission coordination requirements and cost allocation principles of this Final Rule.[452] To the extent that a public utility transmission provider believes such an agreement satisfies these requirements in whole or in part, that public utility transmission provider should describe in its compliance filing how the relevant requirements are

[451] *See* discussion *infra* section IV.E.5.

[452] Public utility transmission providers may continue to enter into such agreements as a means of complying with this Final Rule, but any such agreements that are incorporated into the public utility transmission provider's OATT by reference must be consistent with or superior to this Final Rule.

satisfied by reference to tariff sheets on file with the Commission.

584. We also clarify in response to commenters that the requirement to coordinate with neighboring regions applies to public utility transmission providers within a region as a group, not members within an RTO or ISO acting individually. Therefore, within an RTO or ISO, the RTO or ISO would develop an interregional cost allocation method or methods with its neighbors on behalf of its public utility transmission owning members.

## E. Principles for Regional and Interregional Cost Allocation

### 1. Use of a Principles-Based Approach

#### a. Commission Proposal

585. For the cost allocation method or methods to be just and reasonable and not unduly discriminatory or preferential, the Proposed Rule would require that each cost allocation method satisfy six general cost allocation principles, as set out in the following subsections. The Commission proposed six regional cost allocation principles for each cost allocation method for regional transmission facilities included in the regional transmission plan for purposes of cost allocation and six analogous interregional cost allocation principles for each cost allocation method for a new transmission facility that is located in two neighboring transmission planning regions and is accounted for in the interregional transmission coordination process.

586. Specifically, the Proposed Rule would require that each RTO or ISO (on behalf of its transmission owning members) or the individual public utility transmission providers

in a non-RTO/ISO transmission planning region to demonstrate through a compliance filing that its cost allocation method or methods for new transmission facilities satisfy the following regional cost allocation principles:

> (1) The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.[453] In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.[454]

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[453] *See Illinois Commerce Commission*, 576 F.3d 470 at 476-77 (stating that "[w]e do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars"). *See also MISO Transmission Owners*, 373 F.3d 1361 at 1369 (stating that "we have never required a ratemaking agency to allocate costs with exacting precision"); *Sithe*, 285 F.3d 1 at 5.

[454] As discussed above, the Commission proposed to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements established by state or federal laws or regulations that drive transmission needs. As discussed above, we adopt this requirement in this Final Rule.

(2) Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.

(3) If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio.

(4) The allocation method for the cost of a regional facility must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.[455] However, the transmission planning process in the

[455] In addition, the Commission preliminarily found that this principle does not affect the cross-border cost allocation methods developed by PJM and MISO in response to Commission directives related to their intertwined configuration. *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194, at P 10; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084; *Midwest Indep. Transmission Sys.*

(continued…)

original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this Final Rule.[456]

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*Operator, Inc.*, 129 FERC ¶ 61,102. As noted above, we adopt this finding in this Final Rule.

[456] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

587. The Proposed Rule required each cost allocation method to comply with the following interregional cost allocation principles:

(1) The costs of a new interregional facility must be allocated to each transmission planning region in which that facility is located in a manner that is at least roughly commensurate with the estimated benefits of that facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.

(2) A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that

facility.[457]

(3) If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

(4) Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is

[457] For example, a DC line that runs from a first transmission planning region, through a second transmission planning region, and into a third transmission planning region, with no tap in the second region, may not provide any benefits to the second region.

located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out and explained in detail in the compliance filing for this rule.

588. The Proposed Rule also states that public utility transmission providers will have the first opportunity to develop cost allocation methods for regional and interregional transmission facilities in consultation with stakeholders. In the event that no agreement can be reached, the Commission would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements.

**b. Comments on Use of Principles-Based Approach**

589. Many commenters generally support the use of cost allocation principles although this support is often expressed as part of general support for the Proposed Rule's six proposed cost allocation principles as a package.[458] For example, Dominion believes that by providing cost allocation principles linked to planning, the Commission has taken the correct approach without being overly prescriptive. Dayton Power and Light states that these principles help to reduce uncertainty and provide guidance to interested stakeholders. Energy Future Coalition Group states that the proposed principles follow the direction laid out by the court in the *Illinois Commerce Commission* case, and address legitimate concerns that have been raised by some opponents of broad cost allocation policy over the past two years. On the other hand, as discussed above,[459] some comments oppose any generic action on regional and interregional cost allocation and therefore do not support the use of cost allocation principles to support such action.

590. Almost all commenters urge the Commission not to adopt a "one-size-fits-all" approach to cost allocation and to retain regional and interregional flexibility.[460] For example, APPA and Transmission Agency of Northern California state that the

[458] *E.g.*, DC Energy; WIRES; Dominion; and Dayton Power and Light.

[459] *See* discussion *supra* section II.

[460] *E.g.*, Large Public Power Council; Kansas Corporation Commission; and Nebraska Public Power District.

Commission should not prescribe a uniform approach to interregional transmission cost allocation, and should allow for regional and interregional differences. Transmission Agency of Northern California states that this issue is being addressed at a level where local and regional differences can be addressed more fully, and that it supports the Proposed Rule's assumption that this ongoing process should not be disrupted by this rulemaking.

591. Several commenters ask the Commission to address the Proposed Rule's provision regarding "in the event that no agreement can be reached."[461] They contend that if the Commission adopts a rule providing that it would select a backstop cost allocation method in the event that stakeholders within a region cannot agree to a regional cost allocation method or if regions cannot agree on a cost allocation method for interregional projects, the Commission should provide additional guidance that would help stakeholders to reach agreement. For example, Multiparty Commenters request that the Commission clarify: the level of stakeholder agreement that is acceptable; what would be evidence of an impasse; whether the Commission will defer to the majority; and whether the Commission will extend the time in which to make compliance filings to afford more time to obtain an agreement. Similarly, for interregional cost allocation, Anbaric and PowerBridge recommend that the Commission stipulate a reasonable period

[461] *E.g.*, Anbaric and PowerBridge; AWEA; MidAmerican; Multiparty Commenters; and Southern Companies.

of time for regions to reach agreement on a proposed interregional cost allocation method.

592. Some commenters recommend that the Commission adopt an interregional default cost allocation method if regions cannot agree to such a method themselves, although they note that specific projects will involve unique facts and circumstances. Anbaric and PowerBridge believe that, if regions cannot agree on an interregional cost allocation method, the Commission could impose an agreement based on the facts and circumstances of the project. Massachusetts Municipal and New Hampshire Electric state that, even if an interregional default method is implemented, whether by mutual agreement or by Commission directive, disputes will arise about the application of that method to a given set of facts. Massachusetts Municipal and New Hampshire Electric suggest that the Commission can address these concerns by adopting expedited hearing procedures to be applied in such cases.

593. Other commenters suggest a variation on or alternative to the idea that the Commission adopt a default cost allocation method for regional and interregional cost allocation if stakeholders or regions cannot come to a consensus themselves.[462] Wind Coalition states that having a default cost allocation method would allow construction to

[462] *E.g.*, American Transmission; AWEA; NextEra; and Wind Coalition.

commence while an alternative cost allocation method is being developed, if needed. It states that this would be particularly needed for cross-border cost allocation because there are currently few interregional agreements on cost allocation. Wind Coalition also states that matching cost allocation with a proactive regional or interregional plan is important for justifying regional cost sharing.

594. Some commenters argue that, if a region or regions fail to agree on a method, the Commission should not select a default cost allocation method and also should not select a cost allocation method based on the record here.[463] APPA contends that adoption of a default cost allocation method or particular cost allocation principles or guidelines would influence the prospects for successful regional and interregional negotiation because stakeholders that support the default method will be unwilling to negotiate, knowing that if no agreement is reached, their preferred method will be adopted as the default. PSEG Companies argue that adoption of a single default cost allocation method would be inconsistent with the Proposed Rule's "beneficiary pays" approach. PSEG Companies believe that the "roughly commensurate" standard that the *Illinois Commerce Commission* decision requires will be satisfied only by happenstance under a default cost allocation method. PSEG Companies also disagree with comments by National Grid, AEP, and others that the Commission should institute a default cost allocation method for

[463] *E.g.*, APPA and PSEG Companies.

transmission planning regions that would apply regardless of the nature of the facilities planned (i.e., reliability or economic). PSEG Companies suggest that the Commission clarify how interregional cost allocation will be handled in the absence of an interregional agreement, and it should make clear that the existence of such an agreement is a prerequisite to the assignment of costs to another transmission planning region and its customers. PSEG Companies also state that, if certain regions decline to enter into interregional agreements, the Commission should adopt a "do not harm" standard applicable to such regions as a corollary principle, that is, no region may plan its system in a way that would impose costs on other regions.

595. Some commenters suggest a particular default method that the Commission should adopt if it decides to have a default cost allocation method, such as the SPP highway/byway mechanism.[464] However, other commenters express concern with establishing a "one-size-fits-all" default allocation method.[465] In particular, New England States Committee on Electricity and Identified New England Transmission Owners urge the Commission to reject recommendations to adopt the highway/byway mechanism as a default cost allocation method, instead asking the Commission to respect

[464] Several commenters suggested this method including AWEA, Multiparty Commenters, and NextEra.

[465] *E.g.*, Connecticut & Rhode Island Commissions; Kansas Corporation Commission; Salt River Project; WIRES; and Wisconsin Electric.

regional differences. Sunflower and Mid-Kansas submit that the Final Rule should provide for two-third regional (or interregional) allocation of costs and one-third to the ultimate sink zone for all network upgrades approved through an interregional plan that are needed for variable energy resource integration.

596. With respect to the question of whether the Commission should establish an interim cost allocation method until stakeholders have time to reach consensus, AWEA states that the current market structure and the mechanisms used to allocate costs between transmission providers outside organized market regions needs to mature further before transmission providers in many of these market regions will be able to fully comply with the Proposed Rule. It states that if transmission providers outside organized market regions cannot demonstrate a binding cost allocation method as envisioned by the Proposed Rule, it would be appropriate for the Commission to consider an interim method to address cost allocation in those regions, such as using an "intertie open season" to create a record about the appropriate allocation of costs.

597. NextEra suggests that, for non-RTO regions, regional cost recovery should be promoted by an adder on the transmission rates of public utility transmission providers (and extended to non-jurisdictional utilities via reciprocity). Southern Companies respond that this approach is not feasible because it does not address the fact that their OATT recovers only the share of the cost attributable to their provision of wholesale transmission service. Southern Companies state that even with an adder, third parties

would be limited to recovering approximately 15 percent of their transmission costs, which is comparable to Southern Companies' cost recovery.

598. Massachusetts Departments and MidAmerican state that the Commission should narrowly apply any authority it has to develop a cost allocation method only for specific projects rather than requiring an established mechanism for all projects. For instance, MidAmerican proposes that the Commission adopt a default cost allocation method that would be used only if the stakeholders fail to agree regarding a 500 kV or higher alternative current facility (except high voltage direct current projects) that is identified by the planning process as providing widespread benefits. In this limited case, Mid-American suggests that the Commission adopt a streamlined dispute resolution mechanism with a rebuttable presumption in favor of specified regional and interregional cost allocation methods. MidAmerican states that the record in the proceeding before the Commission on remand from the Seventh Circuit *Illinois Commerce Commission* opinion, demonstrates the reliability, economic, and societal benefits of 500 kV and above transmission, and it also documents that these benefits are realized regionwide whenever extra-high voltage transmission is deployed.

599. Wisconsin Electric states that it may be useful to consider the extent to which statewide stakeholder collaboratives could be effective in helping to resolve interstate cost allocation and cost recovery controversies. It points to California's Renewable Energy Transmission Initiative, which distinguishes stakeholders who are willing to work

in good faith to resolve a project from those who only oppose transmission for self-interested reasons. Northwestern Corporation (Montana) is concerned that the proposal could have uneconomic consequences in that a high-cost allocation solution could be involuntarily allocated to an unwilling entity that has a lower-cost solution. Northern Tier Transmission Group is also worried about the difficulties that would arise in the context of allocating costs to entities that are unwilling to incur them.

600. Some commenters state that the Commission should not close the door on existing or evolving processes.[466] Salt River Project states that requiring involuntary cost sharing would risk foreclosure of promising alternatives and superior options for reliable and least-cost service for customers. Salt River Project is also concerned that arbitrary solutions could result that fail to honor local and regional interests.

601. Dominion states that it is unlikely any imposed allocation method will generate uniform agreement or consensus so if competing principled approaches are proposed, the Commission should not make a ruling in favor of one over the other, but consider whether a blended approach could result in a just and reasonable solution. Southern Companies state that the policies of promoting the expansion of the transmission grid

[466] In addition, WIRES also notes that a default method where regional parties reach an impasse may look more attractive if the Commission's principles provide only generalized guidance. However, WIRES states that greater reliance on principled, up-front guidance for allocating the costs of transmission can provide a high degree of reassurance to parties engaged in negotiating a method. It states that only the Commission can provide this level of certainty.

would be better served by developing a set of reasonable cost allocation principles that would be used to develop a cost allocation method only when an actual, multi-jurisdictional project is pursued. With respect to interregional cost allocation, New York Transmission Owners argue that it is neither necessary nor reasonable for the Commission to impose an interregional cost allocation method if one is not agreed to by the regions.

602. Further, other commenters tell us that principles alone are not enough, and propose alternative solutions. These comments are summarized and addressed below in the discussion of the proposed cost allocation principles.

### c. Commission Determination

603. The Commission requires each public utility transmission provider to show on compliance that its cost allocation method or methods for regional cost allocation and its cost allocation method or methods for interregional cost allocation are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles. Commission determinations on each cost allocation principle are set out in the subsections below. The six regional cost allocation principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation. The six analogous interregional cost allocation principles apply to, and only to, a cost allocation method or methods for a new transmission facility that is located in two neighboring

transmission planning regions and accounted for in the interregional transmission coordination procedure in an OATT. These cost allocation principles do not apply to other new transmission facilities and therefore do not foreclose the opportunity for a developer or individual customer to voluntarily assume the costs of a new transmission facility, as discussed further below in the Participant Funding subsection.

604. We adopt the use of cost allocation principles because we do not want to prescribe a uniform method of cost allocation for new regional and interregional transmission facilities for every transmission planning region. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, we retain regional flexibility and allow the public utility transmission providers in each transmission planning region, as well as pairs of transmission planning regions, to develop transmission cost allocation methods that best suit the needs of each transmission planning region or pair of transmission planning regions, so long as those approaches comply with the regional and interregional cost allocation principles of this Final Rule.

605. The Commission recognizes that a variety of methods for cost allocation may satisfy a set of general principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a

class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[467] Similarly, other methods that would allocate costs to a narrower class of beneficiaries may be appropriate, provided that the methods reflect an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region or pairs of transmission planning regions.

606. In response to comments that request further detail from the Commission on what an appropriate cost allocation method would look like, we conclude that public utility transmission providers in each transmission planning region or pair of transmission planning regions must be allowed the opportunity to determine for themselves the cost allocation method or methods to adopt based on their own regional needs and characteristics, consistent with the six cost allocation principles. With the exception of the limitation on participant funding explained below, we decline to prejudge any particular method or set of methods generically in this Final Rule.

607. In the event of a failure to reach an agreement on a cost allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements. Public utility transmission providers must document in their

[467] We address comments below suggesting that the cost allocation principles be applied to require regional cost sharing for all transmission facilities at 345 kV or higher.

compliance filings the steps they have taken to reach consensus on a cost allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view as necessary for the Commission to make a determination of the appropriate cost allocation method or methods. Each public utility transmission provider must make an individual compliance filing that includes its own proposed method or set of methods of allocating costs and explains how it believes its method or methods satisfy the cost allocation principles and is appropriate for its transmission planning region or pair of transmission planning regions. Groups of public utility transmission providers that agree on a proposed method or methods may make a coordinated filing or filings with their common views. The public utility transmission providers in each transmission planning region or pair of transmission planning regions will have the burden of demonstrating that sufficient effort has been made to comply with the requirements of this Final Rule.

608. Interested parties will be provided an opportunity to comment on these compliance filings, thereby creating a record on which the Commission could develop an appropriate cost allocation method or methods, or establish further procedures to do so. We do not impose other specific filing requirements for what the record should contain. As with any other proceeding before the Commission, should more information become necessary during the Commission's review process, the Commission may request more information from the parties at that time.

609. The Commission will consider in response to compliance filings all issues raised by commenters, such as what constitutes an impasse, whether there should be deference to the majority, and whether granting additional time for the region to continue negotiations would be appropriate. The procedural mechanisms used by the Commission in response to compliance filing(s) will depend on the nature of remaining disputes and what issues are still at stake that are preventing the public utility transmission providers in each transmission planning region or pair of transmission planning regions from reaching a consensus. The Commission will not prejudge the outcome of the dispute by stating at this time whether there should be deference to the views of any particular segment of stakeholders, as suggested by Multiparty Commenters.

610. We decline to adopt a default regional or interregional cost allocation method in this Final Rule. We decline to do so for reasons similar to the reasons we declined to impose a uniform cost allocation method for all transmission planning regions. Many factors may make it appropriate for different transmission planning regions to have different cost allocation methods. It thus would not be practical or reasonable for the Commission to establish such default methods. We agree with APPA and others that having a known default method would cause those who favor it not to negotiate in good faith for an alternative cost allocation method. For these same reasons, we will not establish an interim cost allocation method that applies between the time of the issuance of this Final Rule and the time when stakeholders reach a consensus.

611. The twelve regional and interregional proposed cost allocation principles are discussed below in pairs of six separate subsections. Because the proposed cost allocation principles for regional transmission facilities are very similar to the proposed cost allocation principles for interregional transmission facilities, almost all commenters discussed them together as if they were a single principle. Therefore, the Commission discusses the corresponding sets of cost allocation principles together and, except where otherwise indicated, the Commission determinations regarding each set of cost allocation principles apply to both the regional and interregional transmission facilities in a regional transmission plan for purposes of cost allocation. The cost allocation principles in the Final Rule apply only to those new transmission facilities selected in a regional transmission plan for purposes of cost allocation and new transmission facilities subject to the cost allocation provision of the interregional coordination procedures in an OATT.

### 2. Cost Allocation Principle 1—costs allocated in a way that is roughly commensurate with benefits[468]

#### a. Comments

612. Many commenters generally support the Commission's first proposed cost allocation principle for both regional and interregional cost allocation, which provides that the costs of transmission facilities must be allocated to those that benefit in a manner

[468] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

at least roughly commensurate with the estimated benefits received.[469] For example, Transmission Access Policy Study Group states that the roughly commensurate standard appears to be consistent with the *Illinois Commerce Commission* decision and cost causation principles. Additionally, Westar states that transmission customers in a region should not pay for transmission projects that do not provide commensurate benefits and that only transmission projects that have been thoroughly reviewed in the regional process, show a benefit to the region and are approved by the transmission provider should be included in regional rates. Commenters also generally support the Proposed Rule's proposal to adhere to cost causation principles and also support a "beneficiaries pay" approach.[470] Dayton Power & Light comments that "beneficiaries pay" is the touchstone principle for cost allocation. American Forest & Paper argues that such an approach provides for better incentives for analysis of costs and alternatives.

613. Several commenters, however, support a broader definition of benefits and

[469] *E.g.*, Bay Area Municipal Transmission Group; Santa Clara; Consolidated Edison and Orange & Rockland; Transmission Access Policy Study Group; United States Senators Dorgan and Reid; Professor Ignacio Perez-Arriaga; New York ISO; New York PSC; New York Transmission Owners; Westar; City and County of San Francisco; Conservation Law Foundation; Energy Future Coalition Group; Solar Energy Industries; and EarthJustice.

[470] *E.g.*, Dayton Power & Light; Conservation Law Foundation; and American Forest & Paper.

beneficiaries.[471] NextEra argues that the Final Rule should mandate that planning processes consider various types of benefits, rather than leaving it to a transmission provider's discretion. Old Dominion asserts that adopting a narrow approach to assessing benefits for cost allocation purposes would ignore the broader benefits associated with maintaining and expanding the regional high voltage transmission system—such as more options when making resources decisions in regional markets. Old Dominion notes that restricting the cost causation benefits to a snapshot in time would be problematic for dynamic high voltage regional transmission facilities. National Grid supports a cost allocation method that takes into account both the quantitative and qualitative benefits of transmission. Xcel suggests that the Commission permit methods, such as SPP's highway/byway approach, which broadly allocate costs based on general determination of the benefits provided to a region and stakeholders. AWEA and Multiparty Commenters state that it does not make sense to use cost allocation mechanisms that look only at public policy requirements established by existing state or federal laws or regulations because transmission assets are used for 40 years or longer, and they encourage the Commission to clarify that the appropriate cost allocation mechanisms should take into account the benefits of transmission in addressing likely future public policy requirements as well as existing ones. American Antitrust Institute recommends

[471] *E.g.*, NextEra; AWEA; EarthJustice; and Atlantic Grid.

that the pro-competitive benefits of transmission be recognized.

614. PUC of Ohio recommends that the definition of beneficiary also should include those who gain from the ability to place electricity onto the grid. It states that load should not be solely burdened with the costs of the transmission grid; generation should be responsible for its fair share of the costs. Maine Parties agree, characterizing a beneficiary pays as more consistent with cost causation principles than a cost socialization method.

615. In response to comments supporting a broader definition of benefits, Powerex states that it disagrees that the Proposed Rule is intended to allow for allocation methods that could impose cross-subsidization and states that cost allocation methods for jurisdictional facilities must adhere to cost causation principles. Powerex argues that state or federal public policy requirements do not constitute evidence of a general or undifferentiated benefit to all market participants. Thus, Powerex argues, the Final Rule should emphasize that cost causation principles are and will remain the foundation of all acceptable cost allocation methods and make clear that the Commission rejects cost allocation proposals or outcomes that depart from this principle by promoting cross-subsidization.

616. PSEG Companies take issue with the Proposed Rule's suggestion that the determination of who constitutes a beneficiary may be based on an assessment of "likely future scenarios," arguing that regional planners should not be prognosticators and that

the more "scenarios" that are introduced, the more inexact and speculative their proposed plans and cost allocation determinations will become.

617. Dayton Power & Light seeks clarification of what it considers an ambiguity in regional and interregional Principle 1, which allows a regional transmission planning process to consider the extent to which facilities "in the aggregate" provide benefits.[472] Dayton Power & Light states that this language could be taken to mean that if the existing network benefits a utility, then that is a benefit that justifies the utility allocating to it the incremental costs created by a new transmission project located far away, even if the project did not provide incremental benefits. According to Dayton Power & Light, this result would be inconsistent with *Illinois Commerce Commission* decision.

618. Some commenters also request that the proposed principle be expanded so that the costs of transmission facilities are allocated to those within the planning region and adjacent planning regions that benefit from those facilities.

619. Some commenters request clarification regarding what constitutes "benefits" to be considered in any cost allocation method.[473] Alabama PSC states that the cost allocation proposals are too vague and potentially overbroad, and it requests that the Commission make clear that costs cannot be recovered from retail customers. WIRES requests that

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[472] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164, 174.

[473] *E.g.*, California Municipal Utilities; Northern Tier Transmission Group; Omaha Public Power District; Gaelectric; and Atlantic Grid.

the Commission articulate more clearly the definitions, presumptions, and methods associated with the beneficiary pays approach.

620. A number of commenters differ on what constitutes "benefits" and who constitutes "beneficiaries." Several commenters state concern that the definition of "benefits" could be interpreted too broadly, particularly with respect to transmission projects driven by public policy goals.[474] Atlantic Wind Connection requests clarification as to how the costs associated with public policy initiatives would be fairly assigned to beneficiaries, so that a results-oriented action plan emerges from the process. Transmission Access Policy Study Group argues that benefits are difficult to quantify and cautions the Commission against including generalized social or environmental benefits in cost allocation calculations. Transmission Access Policy Study Group and Colorado Independent Energy Association argue that production cost savings by itself is not sufficient to identify the universe of beneficiaries.[475] Transmission Access Policy Study Group argues, however, that the Commission should clarify that it will not accept cost allocation methods that assign costs regionally based on a presumption of some general, unquantified regional benefits or vague assertions of possible future benefits.

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[474] *E.g.*, Florida PSC; Public Power Council; Transmission Dependent Utility Systems; and Coalition for Fair Transmission Policy.

[475] *E.g.*, Transmission Access Policy Study Group; and Colorado Independent Energy Association.

621. Some commenters raise similar concerns about the difficulty of quantifying benefits, and they suggest that benefits resulting in allocation of costs be direct, clear, and identifiable.[476] Other commenters also believe it is important to make sure cost allocation mechanisms do not favor long-line transmission development or artificially depress the value of local renewable resources.[477] In its reply comments, Ohio Consumers' Council agree that benefits should not be defined too broadly and recommends that the Commission strictly adhere to cost causation principles in implementing the Final Rule. Further, Ohio Consumers' Council suggests that the Commission uphold cost causation principles by requiring substantial evidentiary showings of benefits and costs prior to approving the imposition of regional or interregional transmission costs on consumers. With respect to interregional cost allocation, North Carolina Agencies contend that if the Commission assumes benefits too broadly, a public utility's retail customers may bear a share of costs based on the policy objectives of other states. Alabama PSC shares this concern. According to Western Area Power Administration, only the direct beneficiaries of a project, i.e., beneficiaries that make direct use of the facilities, should be counted as "beneficiaries," and to the extent

[476] *E.g.*, East Texas Cooperatives and G&T Cooperatives.

[477] *E.g.*, New England States Committee on Electricity; Nebraska Public Power District; Sacramento Municipal Utility District; California State Water Project; and Northeast Utilities.

that costs are allocated to such beneficiaries, only the costs associated with the least-cost method of achieving the benefits should be allocated. LS Power states that it is important for the Final Rule to acknowledge that the factors that drive transmission planning do not fully define the range of beneficiaries.

**b. Commission Determination**

622. The Commission adopts the following Cost Allocation Principle 1 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 1: The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[478]

[478] In the Proposed Rule, Regional Cost Allocation Principle 1 referred to "public policy requirements established by State or Federal laws or regulations that may drive transmission needs." As defined in P 2 of this Final Rule, we use "Public Policy

(continued…)

and

> Interregional Cost Allocation Principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[479]

623. As discussed above,[480] requiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts. As the Commission stated in Order No. 890, the one factor

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Requirements" in Regional Cost Allocation Principle 1 and throughout our discussion of the Cost Allocation Principles.

[479] We note that the phrase "individually or in the aggregate" is not contained in Interregional Cost Allocation Principle 1 because interregional transmission facilities are considered facility by facility by pairs of transmission planning regions, unless pairs of transmission planning regions choose to do otherwise.

[480] *See* discussion *supra* P 495 and section V.B.

that it weighs when considering a dispute over cost allocation is whether a proposal fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them.[481] Therefore, it is appropriate here to adopt a cost allocation principle that includes as beneficiaries those that cause costs to be incurred or that benefit from a new transmission facility.

624. However, the Commission is not prescribing a particular definition of "benefits" or "beneficiaries" in this Final Rule. In our view, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Moreover, allowing the flexibility to accommodate a variety of approaches can better advance the goals of this rulemaking. The cost allocation principles are not intended to prescribe a uniform approach, but rather each public utility transmission provider should have the opportunity to first develop its own method or methods. Also, we recognize that regional differences may warrant distinctions in cost allocation methods.

625. While some commenters express concerns that the definition of benefits could be interpreted too broadly or too narrowly, we do not believe that further defining "benefits" in this Final Rule is a necessary or appropriate means to ensure that this will not be the case. We expect that concerns regarding overly narrow or broad interpretation of benefits will be addressed in the first instance during the process of public utility transmission

[481] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

providers consulting with their stakeholders. If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact. This point applies equally to the comments that note the potential difficulties in quantifying benefits. We note in response to Transmission Access Policy Study Group, that any benefit used by public utility transmission providers in a regional cost allocation method or methods must be an identifiable benefit and that the transmission facility cost allocated must be roughly commensurate with that benefit. Western Area Power Administration takes the position that beneficiaries should be limited to those that it describes as making direct use of the transmission facilities in question, but this fails to acknowledge that other benefits may accrue to an interconnected transmission grid.

626. We agree with Powerex that a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method. In response to PSEG Companies, we disagree that basing a determination of who constitutes a "beneficiary" on "likely future scenarios" necessarily would result in inexact and speculative proposed transmission plans and cost allocation methods. Scenario analysis is a common feature of electric power system planning, and we believe that public utility transmission providers are in the best position to apply it in a way that achieves appropriate results in their respective transmission

planning regions.

627. In response to Dayton Power & Light, the provisions of Regional Cost Allocation Principle 1 regarding determination of the beneficiaries of transmission facilities "individually or in the aggregate" refer only to cost allocation for new transmission facilities. The public utility transmission providers in a transmission planning region may propose a cost allocation method that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. We did not intend this language to be a finding that the benefits of existing transmission facilities in and of itself may justify cost sharing for new transmission facilities. We are not ruling on that matter in this Final Rule.

628. We also decline to expand, as requested by some commenters, the scope of beneficiaries for new transmission facilities such that costs may be involuntarily allocated to those within an adjacent planning region that benefit from those facilities. As discussed in adopting Cost Allocation Principle 4 below, the allocation of the cost of a transmission facility that is located entirely within one transmission planning region may not be subject to a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries.

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629. Finally, if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.

### 3. Cost Allocation Principle 2—no involuntary allocation of costs to non-beneficiaries[483]

#### a. Comments

630. Most of the commenters that addressed proposed Cost Allocation Principle 2 support it.[484] Ad Hoc Coalition of Southeastern Utilities and Nebraska Public Power District state that while the proposition in Cost Allocation Principle 2 might seem self supporting, they understand that there are those who would encourage the Commission to mandate regional or even interconnectionwide cost sharing, but the Commission's decision to decline to do so is sensible.

631. Some commenters who express general support also express some concerns. For

[482] *See* discussion *infra* section IV.E.5.

[483] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

[484] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New York ISO; and New York PSC.

example, MISO Transmission Owners urge the Commission to ensure that this principle does not contribute to free rider problems.

632. Some commenters are concerned that the principle could be interpreted too narrowly or too broadly. For instance, NextEra asks that the Commission construe the "no benefit" standard narrowly by providing that there is a benefit if a customer receives any benefit from the transmission facility, including an economic, reliability, or public policy benefit, particularly at or above certain voltage levels, over a reasonable period of time.

633. Some commenters do not support the principle and raise concerns that the "no benefits" language in the principle will rarely, if ever, be applicable to any transmission customer.[485] East Texas Cooperatives argue that by protecting only those that receive no discernible benefit, this principle conflicts with court precedent stating that the Commission cannot approve a pricing scheme that requires utilities to pay for facilities from which its members derive only trivial benefits. East Texas Cooperatives states that Principle 2 does not go far enough, and the Commission should clarify that only those customers who are reasonably expected to receive non-trivial benefits can be allocated costs. Other commenters, such as E.ON and Public Power Council, are worried that there will be stranded costs if a planning process exaggerates the benefits resulting from a

[485] *E.g.*, Transmission Dependent Utility Systems and East Texas Cooperatives.

particular project. Public Power Council believes the Commission should permit cost allocations that mitigate the risk of stranded costs and give due consideration to the impact on ratepayers prior to allocating costs.

634. On the other hand, Xcel is concerned that the principle, taken at face value, gives parties the ability to "opt out" of cost allocation arising from specific projects even as it offers parties the opportunity to participate fully in the planning process. Xcel maintains that the Order No. 890 transmission planning process and the linkage between transmission planning and cost allocation render moot any participant's argument that it receives no benefit. Xcel argues that the Order No. 890 planning principles are designed to result in the best projects to meet the needs of the planning region, and therefore it is unlikely that participants in the planning process would produce a plan with a project or set of projects that do not provide benefits to stakeholders.

635. Alliant Energy asks whether the Commission intended that membership in an ISO or RTO eliminates the prohibition of cost allocation for transmission projects to those entities that do not benefit. Alliant Energy does not believe this was the Commission's intent, but is seeks clarification to confirm its view.

636. Alliant Energy also seeks clarification of the term "transmission facilities" within the context of this principle. It asks whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, or something in between. Alliant Energy believes that such

evaluations should be done on a holistic basis, noting that some individual projects will benefit certain entities more than others but that the evaluation of benefits and costs within the context of a cost allocation determination could reasonably include the cumulative impact of a collection of projects.

### b. Commission Determination

637. The Commission adopts the following Cost Allocation Principle 2 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 2: Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[486]

and

> Interregional Cost Allocation Principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely

[486] We added the words "any of" to the Regional Cost Allocation Principle 2 stated in the Proposed Rule to be consistent with interregional cost allocation Principle 2. We also added "transmission" before "facilities" to clarify the term in this Regional Cost Allocation Principle 2 and throughout our discussion of the Cost Allocation Principles.

> future scenario, must not be involuntarily allocated any of the costs of that transmission facility.

The principle expresses a central tenet of cost causation and is thus essential to proper cost allocation.

638. In response to MISO Transmission Owners that Principle 2 might contribute to free rider problems, we agree that it, like all the other principles adopted in this Final Rule, requires careful consideration and application to ensure that they are implemented appropriately in practice. In response to NextEra, we decline to establish a threshold voltage level to define which benefits would be ineligible for cost allocation in this Final Rule.

639. East Texas Cooperatives is concerned that the Commission is protecting only those that receive no benefits but not those who derive only trivial benefits. It cites the Seventh Circuit's statement in *Illinois Commerce Commission* that emphasized that the Commission is not authorized to approve cost allocation methods that require entities that receive no benefits or benefits that are trivial in relation to the costs to be borne. We note that the court used the term "trivial" in a relative sense, i.e., benefits that are trivial in relation to the costs assigned. This is implied in the concept of cost causation, and we therefore see no reason to amend the Principle 2 to include reference to it. Principle 1 requires that costs be allocated in a way that is roughly commensurate with the benefits received. This precludes an allocation where the benefits received are trivial in relation

to the costs to be borne. Any beneficiaries that believe that the application of the cost allocation method or methods would assign to them costs for benefits, which are trivial, in relation to those costs is free to make a FPA section 205 or 206 filing.

640. We also require that every cost allocation method or methods provide for allocation of the entire prudently incurred cost of a transmission project to prevent stranded costs. We disagree with Xcel that the Principle 2 gives parties the ability to opt out of a Commission-approved cost allocation for a specific transmission project if they merely assert that they receive no benefits from it. Whether an entity is identified as a beneficiary that must be allocated costs of a new transmission facility is not determined by the entity itself but rather through the applicable, Commission-approved transmission planning processes and cost allocation methods. Permitting each entity to opt out would not minimize the regional free rider problem that we seek to minimize in this Final Rule.

641. With respect to Alliant Energy's request for clarification regarding RTO or ISO membership, we clarify that all the cost allocation principles, including Cost Allocation Principle 2 apply the allocation of costs to all new transmission facilities selected in the regional transmission plan for purposes of cost allocation, including RTO and ISO regions. In response to Alliant Energy's request to clarify whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, we reiterate that the public utility transmission providers in a transmission planning region may propose a cost allocation method or

methods that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. To the extent they propose a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, and adequately support their proposal, Cost Allocation Principle 2 would not require a showing that every individual transmission facility in the group of transmission facilities provides benefits to every beneficiary allocated a share of costs of that group of transmission facilities. However, it is required that the aggregate cost of these transmission facilities be allocated roughly commensurate with aggregate benefits.

### 4. Cost Allocation Principle 3—benefit to cost threshold ratio[487]

#### a. Comments

642. Many commenters support the Commission's proposed Cost Allocation Principle 3, finding it to be a reasonable approach that would result in the construction of new transmission projects.[488] For example, ITC Companies states that the Commission's recommended cost threshold ratio is a necessary specification to prevent measures such as the sliding cost benefit ratio employed by MISO, which can require up to a 3 to 1 benefit to cost ratio for large regional long term transmission projects and which has served to frustrate the construction of market efficiency projects. American Transmission

[487] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

[488] *E.g.*, ITC Companies; American Transmission; Omaha Public Power District; PSEG Companies; and Six Cities.

believes that the Commission's proposal seems like a reasonable threshold that would likely result in projects actually being constructed.

643. Nonetheless, some commenters raise specific concerns. While generally supportive of the proposal, MISO Transmission Owners suggest that transmission providers and stakeholders in each planning region be permitted to develop a benefit to cost ratio that is appropriate for that region, provided that ratios are not set so high as to preclude any projects from being built. Similarly, MISO Transmission Owners argue that transmission providers and stakeholders should be permitted to develop appropriate criteria for defining benefits and costs. They also state that the Final Rule should indicate that any benefit to cost ratio for interregional transmission facilities should not supersede the ratio for a region's regional cost allocation. Transmission Dependent Utility Systems support this principle as a general concept, but they argue that it should be modified to ensure that the implementation of any cost benefit analysis is transparent to customers.

644. Several commenters oppose the use of a fixed benefit-cost threshold ratio.[489] A number of them stress the difficulties in quantifying benefits.[490] Some commenters argue that the Commission should focus on regional circumstances.[491] Northern Tier

[489] *E.g.*, Northeast Utilities; Connecticut & Rhode Island Commissions; and Michigan Citizens Against Rate Excess.

[490] *E.g.*, Xcel and Northern Tier Transmission Group.

[491] *E.g.*, Michigan Citizens Against Rate Excess; Xcel; and Massachusetts

(continued…)

Transmission Group suggests that the Commission's focus should be on defining the types of benefits to be measured and how to measure them, rather than establishing a set threshold. Massachusetts Departments are concerned that a failure to reflect the full menu of benefits that could be realized by a proposed project could distort the balance between costs and benefits, and could preclude some beneficial projects at the planning stage that would have otherwise been approved. NextEra requests that benefits for this assessment should cover only economic benefits identified with the project, and not reliability or public policy benefits, as those benefits cannot be quantified in a similar manner.

645. Some commenters would like the Commission to establish either a higher or a lower benefit-cost ratio threshold. New York PSC believes that the proposed threshold is extremely low and does not adequately account for uncertainty in cost estimates and potential cost overruns. Connecticut & Rhode Island Commissions and Massachusetts Departments agree. On the other hand, AWEA, Wisconsin Electric, and NextEra urge the Commission to lower the proposed threshold. AWEA argues that if the Commission adopts the proposed threshold, it should be applied as a ceiling to ensure fair treatment for projects that have broad benefits over time. MEAG Power responds to AWEA's argument for a lower threshold, arguing that AWEA's proposal would unfairly shift to

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Departments.

customers all risks associated with project development.

**b. Commission Determination**

646. The Commission adopts the following Cost Allocation Principle 3 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation,[492] it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.

[492] To ensure consistency in the use of terms in this Final Rule, Cost Allocation Principle 3 as stated in the Proposed Rule has been changed to refer to facilities "selected" in a regional transmission plan, ability of a "public utility transmission provider in a transmission planning region" to use a benefit to cost threshold, and potential Commission approval of a "higher" ratio.

and

> Interregional Cost Allocation Principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation.[493] The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

647. Cost Allocation Principle 3 does not require the use of a benefit to cost ratio threshold. However, if a transmission planning region chooses to have such a threshold, the principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan. Further, it allows

[493] The phrase "net benefits to qualify for interregional cost allocation" differs from the language in regional cost allocation Principle 3 because there is no plan at the interregional level for which projects would be selected. The word "large" was changed to "high" to be consistent with the language in regional cost allocation Principle 3.

public utility providers in a transmission planning region to use a lower ratio without a separate showing and to use a higher threshold if they justify it and the Commission approves a greater ratio.

648. Allowing for a transparent benefit to cost ratio may help certain transmission planning regions to determine which transmission facilities have sufficient net benefits to be selected in the regional transmission plan for purposes of cost allocation. For example, public utility transmission providers in a transmission planning region may want to use such a ratio to account for uncertainty in the calculation of benefits and costs. However, by requiring that a benefit to cost ratio, if adopted, not exceed 1.25 to 1 unless the public utility transmission providers in a transmission planning region justify, and the Commission approves, a greater ratio, will ensure that the ratio is not so high that transmission facilities with significant positive net benefits that would otherwise be selected in the regional transmission plan for purposes of cost allocation are not excluded from the regional transmission plan for purposes of cost allocation despite a positive ratio. The Commission therefore rejects requests to adopt a higher or lower threshold ratio, as advocated by some commenters.

649. In response to specific comments on this principle, the Commission agrees that a benefit to cost ratio should not be set so high as to preclude certain beneficial transmission projects from being constructed. As such, the Commission finds (and several commenters agree) that a benefit to cost ratio of 1.25 to 1 to be a reasonable ratio

that will not act as a barrier to the development and construction of valuable new transmission projects. Furthermore, regarding comments requesting that the Commission decline to establish a benefit to cost threshold given the difficulty in quantifying benefits, we reiterate that the benefit to cost ratio threshold identified in this Final Rule applies only if the public utility transmission providers of a transmission planning region choose to use a benefit to cost ratio to determine which transmission facilities are selected in the regional transmission plan for purposes of cost allocation. They may decide to have no benefit to cost ratio threshold greater than one at all.

650. Furthermore, in response to MISO Transmission Owners, if the issue of whether any benefit to cost ratio threshold for an interregional transmission facility may supersede the ratio for a transmission planning region's regional transmission cost allocation should be presented to us on compliance, we will address it then based on the specific facts in that filing.

### 5. Cost Allocation Principle 4—allocation to be solely within transmission planning region(s) unless those outside voluntarily assume costs[494]

#### a. Comments

651. Nearly all entities that commented on proposed Cost Allocation Principle 4

[494] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

support it.[495] For example, NEPOOL states that it particularly supports Principle 4, citing New England's successful history of voluntarily planning, developing and allocating the costs of interregional projects with its neighbors. New York ISO agrees, stating that it would be appropriate to allow more expansive voluntary cost allocation arrangements, but would be premature and unrealistic to require all regions to adopt specific cost allocation methodologies on an *ex ante* basis that would be applicable to future situations as yet unknown.

652. However, some commenters raise specific concerns. East Texas Cooperatives argue that the restriction on the involuntary allocation of costs on an interregional basis should not be interpreted to prevent a transmission provider from proposing methods to capture the costs associated with the benefits enjoyed by exported energy. MISO Transmission Owners agree with this argument. The New England States Committee on Electricity states that interregional Principle 4 aligns with its view that any allocation method must not transfer costs to New England ratepayers to support development of facilities outside New England unless New England concludes that development of such facilities are the most cost-effective. Northeast Utilities states that it supports the

[495] *E.g.*, ISO New England; Nebraska Public Power District; NEPOOL; New York ISO; New York PSC; Northern California Power Agency; and New York Transmission Owners.

principle in so far as it limits the allocation of costs for interregional projects only to facilities located within neighboring regions.

653. Other commenters argue that the Commission should not limit the application of interregional cost allocation requirements to interregional projects, suggesting that transmission facilities located solely within one region may have benefits in other regions.[496] NextEra recommends modifying Principle 4 so that if transmission facilities within one region clearly benefit another region, the Commission would allow cost recovery by the transmission providers in the region providing the benefits to the other. NextEra maintains that without such a mechanism, the benefitting region would receive a windfall. According to PJM, basing the cost allocation on physical location rather than analyzing power flows, reduced congestion, or improved reliability, is untenable, would invite gaming of the routing and siting process to drive particular cost allocation results, would make negotiations on cost allocation among neighbors more difficult, is inconsistent with a beneficiary pays approach, and is contrary to the existing PJM-MISO interregional cost allocation method. As an alternative, PJM suggests providing for the cost allocation of transmission to all system users that benefit from the increased transfer capability that the new facility provides, thereby moving the decision from controversies surrounding particular generation sources to the future characteristics of the transmission

[496] *See, e.g.*, NextEra; MISO; and MISO Transmission Owners.

system, which is a subject that is more clearly within the Commission's authority and expertise.

654. Similarly, MISO seeks clarification that two or more regions may mutually designate transmission facilities located entirely within a single region as an interregional transmission facility and allocate costs accordingly, which is the approach taken in the current cross-border cost sharing arrangement between MISO and PJM. MISO, along with MISO Transmission Owners, argues that projects located entirely in one region may provide benefits to entities in the neighboring region.

655. Large Public Power Council states that its members cannot at this time commit to entering into interregional agreements regarding cost allocation. It notes that its members are creatures of state and municipal governments, and their authority to enter into binding arrangements is restricted.

656. Finally, the Coalition for Fair Transmission Policy sees an ambiguity in the Proposed Rule. It states that the Proposed Rule allows for costs to be allocated to a beneficiary even when the beneficiary has not entered into a voluntary arrangement to pay those costs, but proposed Cost Allocation Principle 4 states that costs cannot be allocated to an entity or region outside of the geographic boundaries of the planning region where the project is being constructed, absent a voluntary agreement.

### b. Commission Determination

657. The Commission adopts the following Cost Allocation Principle 4 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan[497] must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.[498]

[497] The phrase "an intraregional facility" was replaced with "a transmission facility selected in a regional transmission plan" to be consisted with P 63-65 n this Final Rule.

[498] At the end of the sentence, "entities" has been changed to "beneficiaries" to be precise. Slight wording changes have been made to the last sentence in this regional cost allocation Principle 4 and interregional cost allocation Principle 4 to clarify the point being made.

and

> Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located.[499] However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.[500]

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[499] The first two sentences of interregional cost allocation Principle 4 differ from regional cost allocation Principle 4 because at the interregional level, there may be a scenario where a transmission facility is located in one transmission planning region but provides benefits to another transmission planning region. For example, if regions A and B plan an interregional transmission facility that they believe benefits region C, regions A and B cannot allocate costs of that facility to region C involuntarily.

[500] "Transmission facility" was changed to "upgrade" in each instance in this

(continued…)

658. Regarding the allocation of the cost of a transmission facility that is located entirely within one transmission planning region and that is intended to export electric energy from that transmission planning region to another transmission planning region, the public utility transmission providers in the exporting transmission planning region may not have a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries. The public utility transmission providers in such transmission planning regions may, however, negotiate an agreement to share the transmission facility's costs with the beneficiaries in another transmission planning region, as they always have been free to do. Doing so is not inconsistent with Regional Cost Allocation Principle 4.

659. Regarding the allocation of the cost of an interregional transmission facility that is located in two or more neighboring transmission planning regions and that is intended to export electric energy from one such transmission planning region to the other transmission planning region, this Final Rule requires that the public utility transmission providers in each pair of transmission planning regions have an interregional cost allocation method or methods for sharing the cost of such transmission facilities.

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sentence to make it consistent with the last sentence in regional cost allocation Principle 4. The end of the last sentence is revised to be consistent with Regional Cost Allocation Principle 4.

However, Interregional Cost Allocation Principle 4 does not permit the cost allocation method or methods for those two transmission planning regions to assign the cost of the transmission facility to beneficiaries in a third transmission planning region except where the beneficiaries in the third transmission planning region voluntarily reach an agreement with the two transmission planning regions in which the transmission line is located. They also may satisfy the requirements of this Final Rule by having an interregional cost allocation method or methods for more than two transmission planning regions, although this Final Rule does not require them to do so.

660. We decline to adopt NextEra's recommendation that we modify Principle 4 to allow cost allocation by the public utility transmission providers in one transmission planning region to beneficiaries in another transmission planning region.[501] We acknowledge that this Final Rule's approach may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility. Nonetheless, the Commission finds this approach to be appropriate. For the reasons discussed herein, we are establishing a closer link between regional transmission planning and cost allocation, both of which involve the identification of beneficiaries. In light of that closer link, we find that allowing one region to allocate costs unilaterally to entities in another region

[501] *See* discussion *supra* section IV.D.

would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. Indeed, if the Commission expected such participation, the resulting regional transmission planning processes would amount to interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner. The Commission is not requiring either interconnectionwide planning or interconnectionwide cost allocation.

661. MISO's and PJM's comments raise a similar issue that our proposed reforms inappropriately limit interregional cost allocation to those beneficiaries that are physically located in the transmission planning region in which the transmission facility is located. We find that this approach would raise the same concerns discussed immediately above.

662. We recognize that MISO and PJM have an existing cross-border cost allocation method that permits them, in certain cases, to allocate to one RTO the cost of a transmission facility that is located entirely within the other RTO, even if the facility does not cross the border between their two regions. Because MISO and PJM developed their cross-border allocation method in response to Commission directives related to MISO and PJM's intertwined configuration, we find that MISO and PJM are not required by this Final Rule to revise their existing cross-border allocation method in response to Cost Allocation Principle 4. If MISO and PJM believe their existing cross-border cost allocation method fulfills other principles discussed herein, they may explain that in the

filings they make in compliance with this Final Rule.

663. In response to Large Public Power Council, as we discuss below,[502] a non-public utility transmission provider seeking to maintain a safe harbor tariff must ensure that the provisions of that tariff substantially conform, or are superior to, the *pro forma* OATT as it has been revised by this Final Rule. However, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.

664. We disagree with Coalition for Fair Transmission Policy's argument that there is an ambiguity in our reforms that allows for costs to be allocated to a beneficiary when the beneficiary has not entered into a voluntary arrangement to pay those costs, while also providing in Cost Allocation Principle 4 that the costs of transmission facilities in a regional transmission plan cannot be allocated to an entity in another transmission planning region, absent a voluntary agreement.

### 6. Cost Allocation Principle 5—transparent method for determining benefits and identifying beneficiaries[503]

#### a. Comments

665. Nearly all commenters that address this proposed principle supported it.[504] PSEG

[502] *See* discussion *infra* section V.B.

[503] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

[504] *E.g.*, SPP; Transmission Access Policy Study Group; and Transmission

(continued…)

Companies agree that there is a need for transparent cost allocation and that customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. Further, PSEG Companies state that it should be clear which customers are benefiting from and paying for system upgrades before they are built, as this will minimize after-the-fact debates and litigation.

666. Some commenters that support the principle caution that it will be difficult to determine costs and benefits with mathematical precision.[505] In light of such difficulties, Connecticut & Rhode Island Commissions suggest that transmission cost allocation methods be pragmatic. DC Energy raises concerns about the use of biased assessments, and it suggests that one method for improving the reliability of cost-benefit analyses is to require that only direct costs and benefits be considered in economic studies since they offer greater certainty. PSEG Companies agree with the proposed principle and suggest that for non-reliability projects, there should be a more definitive link between identified beneficiaries and the costs to be paid.

667. Several commenters raise specific issues with respect to the proposed principle. Transmission Dependent Utility Systems urge the Commission to recognize that

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Dependent Utility Systems.

[505] *E.g.*, NextEra and Sunflower and Mid-Kansas.

transparency alone is insufficient without load serving entity involvement in the planning and development of the cost allocation method. Finally, MISO Transmission Owners argue that current RTO processes provide significant transparency.

**b. Commission Determination**

668. The Commission adopts the following Cost Allocation Principle 5 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

and

> Interregional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a
>
> stakeholder to determine how they were applied to a proposed

interregional transmission facility.[506]

669. Requiring cost allocation methods and their corresponding data requirements for determining benefits and beneficiaries to be open and transparent ensures that such methods are just and reasonable and not unduly discriminatory or preferential. Furthermore, greater stakeholder access to cost allocation information will help aid in the development and construction of new transmission, as stakeholders will be able to see clearly who is benefiting from, and subsequently who has to pay for, the transmission investment. In addition, the Commission agrees that such access to information may avoid contentious litigation or prolonged debate among stakeholders.

670. As the Commission stated in the Proposed Rule, we recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. However, the Commission finds that a transparent transmission planning process is the appropriate forum to address these issues, and by addressing these issues, there will be a greater likelihood that regions can build the new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

671. We acknowledge the concerns that the method or methods for determining

[506] "Interregional" has been added before "transmission facility" at the end of the sentence to be precise.

benefits and beneficiaries must balance being pragmatic and implementable with being accurate and unbiased. Cost Allocation Principle 5 requires that the method or methods be known and transparent. As stakeholders participate in the development of such methods, their input should ensure that the method or methods ultimately agreed upon is balanced and does not favor any particular entity. In developing this method or methods, public utility transmission providers and their stakeholders are also free to consider suggestions, such as those made by DC Energy, that only direct costs and benefits should be considered in economic studies. We will not, however, opine on such suggestions at this time. Rather, the Commission will review such matters once the cost allocation method or methods are filed on compliance.

672. In response to MISO Transmission Owners, the Commission declines at this time to rule on whether any current RTO and ISO processes provide enough transparency to satisfy Cost Allocation Principle 5. Such determinations will be made upon the submittal of a compliance filing by any RTO or ISO.

### 7. Cost Allocation Principle 6—different methods for different types of facilities[507]

#### a. Comments

673. Many commenters generally support proposed Cost Allocation Principle 6, arguing that transmission projects are built for different purposes, such as for reliability or economic reasons, and different methods may therefore be appropriate.[508] Four G&T Cooperatives state that the planning regions should be given latitude to determine within reason the range of benefits that can be considered for cost allocation purposes, as well as the prioritization and relative value of such benefits. Pennsylvania PUC contends that cost allocation methods should maintain stable transmission rates that will be preferable both to the customers who pay the rates and the system planners who have to forecast future expenditures for the system. It argues that a cost allocation method should be flexible enough to accommodate different types of renewable energy from a diversity of sources, public policy changes, and potential shifts from older fossil fuel generation and development of other energy sources such as nuclear generation. Pennsylvania PUC also suggests that a cost allocation method be able to accommodate different types of facilities

[507] For the full text of this principle, *see* P 586 for regional cost allocation and P 587 for interregional cost allocation.

[508] *E.g.*, Indianapolis Power & Light; NEPOOL; Public Power Council; Northeast Utilities; New Jersey Board; E.ON; American Transmission; Dayton Power and Light; Delaware PSC; Dominion; New England States Committee on Electricity; and PSEG Companies.

such as those serving renewable and non-renewable generators, both economic and reliability projects, as well as specialized projects such as generator interconnection facilities. MISO Transmission Owners agree and state that the applicable method should be determined through the stakeholder planning process. Dayton Power & Light states that one method may be appropriate, such as the beneficiary-pays approach, but the method by which beneficiaries are identified may depend on the type of project involved. New Jersey Board also supports flexibility and states that further analysis must be completed to determine how best to allocate costs for transmission driven primarily by public policy requirements because the beneficiaries may differ markedly from the beneficiaries of transmission facilities built for reliability purposes.

674. PSEG Companies request that reliability and non-reliability projects be treated differently for cost allocation purposes, and they advocate adopting a voting mechanism for economic projects that would require that proposed economic upgrades be voted on by the entities that have been deemed to benefit from them and who in turn would be responsible for paying for them. National Grid, however, is concerned about the use of supermajority voting requirements for economic transmission projects. In response, Con Edison points favorably to New York ISO's supermajority voting requirements for economic transmission projects in its transmission planning process.

675. In its reply comments, PJM proposes a possible way to reconcile what it views as competing directives in the Proposed Rule regarding transmission planning and cost

allocation related to economic, reliability, and public policy projects. Economic and reliability projects would be included in one category, under which a beneficiary pays approach would match the planning purposes used (e.g., avoiding a violation of a reliability standard). Public policy projects would comprise the second category, under which the Commission would align the planning and cost allocation for such projects with regional action taken by states sharing similar public policy objectives. PJM suggests that regions could form interstate compacts to identify shared public policy goals and resource requirements and accept the allocation of costs associated with those projects. PJM further suggests a "safe harbor" to prevent states from having to absorb costs for public policy projects undertaken in other states.

676. Large Public Power Council believes that the interregional allocation of costs is a topic on which consensus is feasible only in the context of specific projects proposed by project developers to satisfy identified market needs.

677. Some commenters point to existing approaches as being adequate to meet this principle. Northeast Utilities states that a comprehensive approach using the current New England method should be appropriate. Northeast Utilities contends that the existing cost allocation rules in the ISO-New England OATT would meet the proposed requirements for regional cost allocation with the addition of a clearer cost allocation method for economic projects and a separately stated method for projects intended to meet public policy requirements.

678. Some commenters are concerned as to whether the Commission should allow different cost allocation methods for different facilities.[509] These commenters make several arguments: (1) new transmission facilities seldom serve one function and may provide general reliability and other benefits to the transmission system; (2) the benefits of a given project may vary over time; and (3) such designations have been the source of substantial delays and conflict as planning participants spend time and resources arguing over a project's designation.

679. Xcel states that while it does not oppose the concept of using different cost allocation mechanisms for projects with different drivers, it believes that an excessive amount of time is being spent splitting benefits into their component buckets. It argues that the appropriate focus of cost allocation methods instead should be determining the multiple benefits that any transmission projects provide to a planning region and its stakeholders. Xcel explains that one objective of the state transmission certification process is to ensure that, regardless of the initial driver, projects are ultimately scoped and right-sized to provide multiple benefits. Xcel thus argues that cost allocation methods should concentrate on identifying and measuring multiple benefits that transmission facilities provide, rather than developing a new cost allocation method for

[509] *E.g.*, ITC Companies; Multiparty Commenters; NextEra; and Wind Coalition.

each initial project driver.

680. Multiparty Commenters express concern that there could be a proliferation of cost allocation designs if the Commission allows different cost allocation methods for different types of facilities and for interregional and regional planning processes. They believe that this will lead to protracted disputes about the function of a transmission facility.

681. Transmission Dependent Utility Systems believe that Cost Allocation Principle 6 could place too much discretion in the hands of the transmission providers, particularly in non-RTO/ISO regions, and they urge the Commission to require transmission providers to make these decisions in collaboration with customers. They state that including load serving entities in these discussions would go a long way towards alleviating their concern with having a separate cost allocation method for facilities driven by public policy requirements.

682. Several commenters seek clarification of Principle 6. New York ISO seeks clarification that public utility transmission providers may adopt cost allocation methods for different types of transmission projects without creating a specific cost allocation mechanism applicable solely to public policy projects. New York ISO states that the Proposed Rule appears to contemplate this and contends that such a clarification would be appropriate, especially for regions such as New York that do not currently have a rule

requiring that public policy projects be constructed. New York ISO states that such cost allocation methods can and should be determined on a project-specific basis depending on the policy driving the agreed-upon transmission project.

683. Long Island Power Authority suggests that imposing a single regional cost allocation method for public policy driven projects may inhibit the development of transmission that facilitates the interconnection of renewable energy generation and would allocate costs of each public policy driven project to the same beneficiaries, leading to the assignment of duplicative costs to specific entities and to increases in rates that reduce, or possibly eliminate, an entity's ability to incur costs for its own renewable generation or energy efficiency goals. Long Island Power Authority therefore believes the Final Rule should not direct project costs to non-beneficiaries and not impose costs that prevent non-jurisdictional entities from satisfying their own lawful public policy goals.

684. Alliant Energy seeks clarification that for purposes of Principle 6 the terms "region" and "regional" cover the entire RTO or ISO footprint in the case where there is a Commission-approved planning region within an RTO or ISO, such as American Transmission within MISO. Alliant Energy contends that Principle 6 invites the opportunity for discrimination and unintended consequences if the Commission determines that a region could constitute a single transmission provider within the RTO or ISO footprint. It states that cost allocation policies within an RTO or ISO footprint

must be consistent.

**b. Commission Determination**

685. The Commission adopts the following Cost Allocation Principle 6 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 6: A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[510] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

and

> Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to

[510] "Public Policy Requirements" replaces "public policy requirements established by State or Federal laws or regulations that may drive transmission needs" as defined in P 2 of this Final Rule.

> achieve Public Policy Requirements.[511] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.[512]

686. We agree with the Pennsylvania PUC and others that transmission planning regions should be afforded the opportunity to develop a different cost allocation method for different transmission project types.[513] The development of such cost allocation method, however, rests with the public utility transmission providers participating in regional transmission planning processes in consultation with stakeholders. Cost Allocation Principle 6 permits but does not require the public utilities in a transmission planning region to designate different types of transmission facilities, and it permits but does not require the public utilities in a transmission planning region that choose to designate different types of transmission facilities to have a different cost allocation method for each type. However, we clarify that if the public utilities choose to have a different cost allocation method for each type of transmission facility, there can be only

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[511] "Public Policy Requirements" replaces "public policy requirements established by State or Federal laws or regulations that may drive transmission needs" as defined in P 2 of this Final Rule.

[512] The word "clearly" has been added to this sentence to make it consistent with the last sentence in regional cost allocation Principle 6.

[513] We note that a method, such as a highway-byway method for a reliability project, may itself further distinguish types of facilities, for example by voltage, and allocate costs differently for each type.

one cost allocation method for each type.

687. It may be appropriate to have different cost allocation methods for transmission facilities that are planned for different purposes or planned pursuant to different regional transmission planning processes, provided that these methods are applied consistently. In particular, in response to some commenters, we clarify that we are not requiring a distinct regional or interregional cost allocation method applicable solely to transmission facilities for Public Policy Requirements and that are selected in a regional transmission plan for purposes of cost allocation, but we allow it.

688. Moreover, as the Commission recognized in Order No. 890, states have a critical role with respect to transmission planning.[514] That role may be particularly important with respect to planning for transmission needs driven by Public Policy Requirements, where multiple states may be impacted by the selection (or cost) of a given transmission project needed to meet transmission needs driven by a particular state's Public Policy Requirement. Therefore, we strongly encourage states to participate actively not only in transmission planning processes in general, but specifically in the identification of transmission needs driven by Public Policy Requirements. We also note that agreements among states with respect to cost allocation may be particularly important for transmission facilities designed to meet transmission needs driven by Public Policy

[514] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

Requirements. States could pursue such agreements in various forms, including a committee of state regulators or through a compact among states that receives appropriate approval from Congress.

689. We leave it to each transmission planning region or pair of transmission planning regions to propose on compliance whether, and how, to distinguish between types of transmission facilities. We also note that a public utility transmission provider together with other public utility transmission providers in a transmission planning region, and an RTO or ISO, which is itself a public utility transmission provider, may have a single cost allocation method for all proposed transmission facilities or different methods for different types of transmission facilities. For example, cost allocation methods may distinguish among transmission facilities that are driven by needs associated with maintaining reliability, addressing economic considerations, and achieving Public Policy Requirements, all of which would be required to be considered in the regional transmission planning process as explained in this Final Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of transmission project currently have transmission planning procedures and cost allocation methods that refer only to the first two types of transmission projects. This Final Rule allows a public utility transmission provider through its participation in a transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three types is considered in the regional

transmission planning process and there is a means for allocating the costs of each type of transmission facility to beneficiaries. In response to PSEG Companies, we clarify that a regional cost allocation method for one type of regional transmission facility or for all regional transmission facilities may include voting requirements for identified beneficiaries to vote on proposed transmission facilities.

690. However, a public utility transmission provider must have a regional cost allocation method for any transmission facility selected in a regional transmission plan for purposes of cost allocation. It may not designate a type of transmission facility that has no regional cost allocation method applied to it, which would effectively exclude that type of transmission facility from being selected in a regional transmission plan for purposes of cost allocation. In response to New York ISO and Long Island Power Authority, a transmission facility proposed to address a Public Policy Requirement must be eligible for selection in a regional transmission plan for purposes of cost allocation and must not be designated as a type of transmission facility for which the cost allocation method must be determined only on a project-specific basis. However, in contrast to what New York ISO's comment implies, the regional cost allocation method for such a transmission facility may take into account the transmission needs driven by a Public Policy Requirement, who is responsible for complying with that Public Policy Requirement, and who benefits from the transmission facility. If a regional transmission plan determines that a transmission facility serves several functions, as many commenters

point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.

691. As stated elsewhere, we decline to opine here on whether any existing processes satisfy Cost Allocation Principle 6 in the regional and interregional context. For example, if a region believes that its regional transmission planning process meets Regional Cost Allocation Principle 6 for all facilities, including transmission facilities driven by a Public Policy Requirement, it may submit evidence in support of this position in a compliance filing pursuant to this Final Rule.

692. Some commenters are concerned that designation of transmission facility type can result in substantial delay because transmission facilities may serve multiple functions and benefits and beneficiaries may vary over time. This concern should be addressed in each region's transmission planning process. However, we note that many regional transmission planning processes currently have mechanisms for distinguishing between types of transmission facilities, and there is no reason to believe that transmission facilities designation necessarily results in a substantial delay.

693. In response to Alliant Energy's comment, the Commission addressed this concern in the regional transmission planning section above.[515]

[515] *See* discussion *supra* section III.A.

### 8. Whether To Establish Other Cost Allocation Principles

#### a. Commission Proposal

694. The Proposed Rule sought comment on whether additional principles should apply to cost allocation for either regional or interregional transmission facilities, and it asked commenters to submit and explain the need for those principles.[516]

#### b. Comments

695. Six Cities ask the Commission to include a new principle or a corollary requirement that the transmission planning processes include provisions to encourage cost containment, a point echoed in other comments on cost allocation.[517] The New England States Committee on Electricity also argues that the Commission should establish transmission cost control and review mechanisms to ensure that construction is performed as efficiently as possible and the costs incurred are reasonable.

696. ELCON and Associated Industrial Groups urge the Commission to adopt two

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[516] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

[517] *E.g.*, California Commissions; California Municipal Utilities; City of Santa Clara; Connecticut & Rhode Island Commissions; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Northeast Utilities; Northern California Power Agency; and Transmission Agency of Northern California. While San Diego Gas & Electric agrees that it is appropriate for commenters to seek safeguards with respect to cost overruns, it takes issue as a factual matter with California Municipal Utilities' inclusion of the Sunrise-Powerlink project as one that is a clear example that cost overruns are endemic.

technical principles related to the costs of new transmission investments being allocated on a representatively-determined capacity (MW) basis, not on an volumetric (MWh) basis and periodic adjustment of cost allocation to reflect changes in power flows.[518] However, ITC Companies do not support periodic adjustments of cost allocation and describe it as disruptive and potentially risky.

697. Other commenters propose principles that look to safeguard particular participants in the transmission planning process. For example, City of Los Angeles Department of Water and Power states that there should be appropriate safeguards that allow non-public utilities to seek required approvals before they are allocated costs for new transmission projects, and that participation in the regional transmission planning process by non-public utilities remain voluntary. Similarly, Transmission Dependent Utility Systems state that if a particular customer is not allowed to participate fully in a regional planning process, there should be a presumption that the customer is not receiving benefits from the regional plan.

698. San Diego Gas & Electric proposed policy changes for transmission projects that span multiple balancing authority areas and for which a voluntarily negotiated cost allocation arrangement proves feasible. Its proposed policy changes focused on payment by loads, allocation of costs to balancing authority areas that do or do not benefit, and

[518] *See also* East Texas Cooperatives and Maine Parties.

encouragement for non-jurisdictional governmental agencies to adopt reciprocal cost allocation policies.

699. Michigan Citizens Against Rate Excess proposed three additional principles that limit transmission costs driven by public policy requirements to the state or states of origin,[519] that transmission cost recovery should not be a means to subsidize non-transmission projects, and that no state or region should shoulder the cost alone when benefits accrue to others as well, namely for reliability projects only.

700. PUC of Ohio maintains that the Commission should consider principles when considering any long-term transmission rate design that provide the utility the opportunity to recover an authorized revenue amount, is equitable, provides for customer understanding and rate continuity, minimizes customer impact and undue cost shifts, and recognizes the use and benefits of the transmission system.

701. Environmental Defense Fund, the Wilderness Society, and Western Resource Advocates recommended principles that they argue will assist in identifying the full range of benefits that must be accounted for when justifying a project.[520] They state that project costs should be allocated consistent with the range/distribution of benefits that are

[519] *See also* Electricity Consumers Resource Council and the Associated Industrial Groups and Public Power Council.

[520] *E.g.*, Environmental Defense Fund; Wilderness Society; and Western Resource Advocates. Sonoran Institute also proposes the second and third principles proposed by Environmental Defense Fund and Wilderness Society and Western Resource Advocates.

likely to accrue in both the near- and long-term, that the benefits of projects must include carbon emissions reductions and the attainment of other state and federal policy imperatives, and that beneficiaries under any beneficiaries-pay cost allocation policy be defined to include consideration of the myriad of beneficial outcomes described above, as well as other benefits likely to accrue to transmission system users over the life of the grid investment.

702. American Antitrust Institute states that the Commission should consider how cost-benefit tests for cost allocation and recovery can be designed to promote competition and encourages the Commission to carefully scrutinize cost allocation approaches based on voting rules that give incumbent utility transmission providers the ability to vote against economic transmission projects that benefit ratepayers.

703. Energy Consulting Group suggests that beneficiaries, including those receiving firm transmission service should to be obligated to pay the allocated costs of the improvements through a specified tariff rate and relieved of any obligations to pay current OATT rates for improvements.

### c. Commission Determination

704. We agree with Six Cities, New England States Committee on Electricity, and others that cost containment is important. However, we decline to establish a corresponding cost allocation principle as recommended, primarily because cost containment concerns the level of costs, not how costs should be allocated among

beneficiaries. While we understand and agree that those receiving a cost allocation are appropriately concerned that the level of the cost being allocated should be controlled accordingly, we do not believe that a new principle or corollary requirement in this Final Rule is the appropriate mechanism to promote cost containment.

705. We have considered all the other additional principles proposed by commenters but decline to adopt them. We do not believe that any additional principles are necessary at this time. Moreover, we believe that many of the suggestions of commenters, if required by this Final Rule, would limit the flexibility we provide in this Final Rule for public utility transmission providers to propose the appropriate cost allocation method or methods for their transmission planning region or pair of transmission planning regions. If a commenter believes that one or more of its suggestions is consistent with the six principles we adopt herein, that commenter is free to work within a regional stakeholder process to see if its concerns could be addressed. We will permit each transmission planning region or pair of transmission planning regions to propose cost allocation methods that satisfy additional requirements that they deem necessary to meet the specific needs of that transmission planning region or transmission planning regions provided they are consistent with the cost allocation principles of this Final Rule. Any such requirements should be submitted as part of the cost allocation method or methods on compliance, along with an explanation of how they comply with the requirements of this Final Rule.

### F. Application of the Cost Allocation Principles

706. The Proposed Rule addressed several potential applications of the cost allocation principles, seeking general comment on the appropriateness of these six cost allocation principles and how they should be applied to the costs of new regional and interregional transmission facilities that are eligible for cost allocation.[521]

#### 1. Whether To Have Broad Regional Cost Allocation for Extra-High Voltage Facilities

##### a. Commission Proposal

707. The Commission declined in the Proposed Rule to address in the abstract and in the absence of a record whether several candidate cost allocation methods, either in use today in a region or proposed by some commenters, would satisfy the proposed regional and interregional cost allocation principles.

##### b. Comments on Cost Allocation for Extra-High Voltage Facilities

708. Several commenters recommend that the Commission establish a rebuttable presumption that the costs of extra-high voltage transmission facilities be allocated widely across a region.

709. NextEra argues that extra-high voltage lines, typically 345 kV and above, provide

[521] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

regional benefits, and that the Commission should require that every cost allocation method include a rebuttable presumption that the costs of such lines will be allocated widely. WIRES agrees, pointing out that this is essentially the approach taken in PJM for projects above 500 kV. NextEra suggests that those seeking to rebut this presumption in the context of a particular extra-high voltage project should bear the burden of showing they receive no benefits from the project. To accomplish this, NextEra recommends that the Commission adopt a *pro forma* transmission cost allocation method, and that transmission providers and stakeholders could either follow the *pro forma* model or propose a method that is consistent with or superior to that model. Multiparty Commenters also support a rebuttable presumption for extra-high voltage lines.[522] Similarly, AEP argues that extra-high voltage facilities provide regionwide benefits and the costs of such facilities should be allocated widely across a region. AEP also suggests that extra-high voltage AC facilities that interconnect electrical regions and that are identified as needed under the applicable interregional coordination agreement benefit both regions, and AEP states that the costs of such facilities should be allocated across those regions. Clean Line supports allocating the costs for extra-high voltage lines across the largest region possible.

[522] Multiparty Commenters append an analysis performed by CRA International that purports to show the widely dispersed benefits of extra-high voltage transmission facilities (CRA Study).

710. Baltimore Gas & Electric submits that the Final Rule should apply highway/byway principles to projects that traverse RTOs and to projects within RTOs. It states that the cost allocation principles espoused in the Proposed Rule should be adopted, and that the Commission should at least allow for the Opinion No. 494 method to be continued in PJM,[523] regardless of the methods that are deemed appropriate for other RTOs.[524] However, Baltimore Gas & Electric states that other RTOs must maintain cost allocation mechanisms with respect to each other that provide for reciprocal treatment. It states that new, high voltage, RTO-approved facilities should be paid for uniformly by all rate zones because they provide significant benefits to all rate zones.

711. Several reply commenters oppose proposals to establish a rebuttable presumption for extra-high voltage facilities.[525] Large Public Power Council argues that such proposals cannot be squared with the cost allocation principle set forth in *Illinois Commerce Commission* that utilities cannot be required to pay for facilities from which

[523] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), Opinion No. 494-A, 112 FERC ¶ 61,082 (2008) (cost allocation methods for new transmission facilities that distinguished between facilities below and above 500 kV), *remanded*, *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009).

[524] Delaware PSC and American Forest & Paper also support PJM's cost allocation method for high voltage facilities. American Forest & Paper asserts PJM's method is preferable to the energy allocator method proposed in MISO.

[525] *E.g.*, Coalition for Fair Transmission Policy; Ad Hoc Coalition of Southeastern Utilities; Southern Companies; Large Public Power Council; East Texas Cooperatives; New England States Committee on Electricity; and APPA.

its members derive no or only trivial benefits. Ad Hoc Coalition of Southeastern Utilities replies that there is no basis to presume that an extra-high voltage transmission overlay is beneficial to all customers, and that such a position is inconsistent with *Illinois Commerce Commission*. Ad Hoc Coalition of Southeastern Utilities emphasizes that the addition of extra-high voltage facilities can overload the underlying transmission system and change power flows, requiring upgrades to lower voltage lines and operational changes. Ad Hoc Coalition of Southeastern Utilities contends that broadly socializing the costs of extra-high voltage facilities could bias the integrated resource planning process total-cost analyses toward such facilities in that at least some of their costs will be spread throughout the region and not incurred by the utility causing the need for the facilities. Similarly, Southern Companies states that its integrated resource planning has not shown that extra-high voltage lines are a cost-effective, reliable solution to meeting identified transmission needs and that constructing such lines in the Southeast and then broadly socializing their costs over the entire load in the region would result in higher costs to consumers than implementing non-extra-high voltage solutions. Southern Companies also argue that such an approach would skew the evaluations of which transmission and non-transmission alternatives are the least cost means to meet an identified need. MEAG Power provides illustrations of how such a proposal could result in unjust and unreasonable rates. Coalition for Fair Transmission Policy argues that the CRA Study filed by Multiparty Commenters is flawed because it neglects to mention that in some

cases extra-high voltage facilities impose costs on some parts of a region as well, and that such impacts can be ascertained only by examining specific projects. MEAG Power similarly asserts that the CRA study is flawed for a number of reasons, including the fact that it examines only the existing grid, omits several regions from its analysis and fails to estimate any dollar benefits accruing to any party.

712. In addition, in its reply comments, SoCal Edison disagrees with NextEra's proposal for a *pro forma* cost allocation agreement, arguing that there is not sufficient evidence to determine that such an approach is consistent with the principle that costs be allocated roughly commensurate with benefits.

### c. Commission Determination

713. We are not persuaded to adopt a rebuttable presumption that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely across a transmission planning region. Such a presumption would be akin to a default cost allocation method which, as discussed above,[526] we do not adopt. For the same reason, we do not agree that a *pro forma* cost allocation method is appropriate.

714. The Commission recognizes and intends that several approaches to cost allocation may satisfy the principles adopted in this Final Rule. If it were otherwise, the offer of regional flexibility would be an empty offer. Therefore, we do not impose a single cost

[526] *See* discussion *supra* section IV.E.1.

allocation method for any transmission planning region. If public utility transmission providers and their stakeholders in a transmission planning region reach a consensus that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely and that this would result in a distribution of costs that is at least roughly commensurate with the benefits received, and support this conclusion with evidence, they may submit the method to the Commission on compliance.

### 2. Whether To Limit the Use of Participant Funding

#### a. Commission Proposal

715. Following the presentation of these six cost allocation principles in the Proposed Rule, the Commission discussed their application to participant funding as a regional or interregional cost allocation method for satisfying these principles. The Commission explained that in transmission planning regions outside of the RTO and ISO footprints, many of the cost allocation methods that the Commission accepted in the Order No. 890 compliance proceedings rely exclusively on a "participant funding" approach to cost allocation, in which the costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.[527] The Commission proposed that participant funding is not a cost allocation method that would satisfy these principles. The Commission further noted that a cost allocation method that relies exclusively on a participant funding

[527] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 121-28.

approach, without respect to other beneficiaries of a transmission facility, increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. However, the Proposed Rule did not prohibit voluntary participant funding for those that choose to use it.

### b. Comments on Limiting Participant Funding

716. Many commenters generally agree that a cost allocation method based exclusively on a participant funding approach neither achieves the goal of timely development of building transmission facilities nor results in just and reasonable rates.[528] In support of this position, several commenters maintain that participant funding does not allocate the costs of new regional transmission projects to their multiple beneficiaries.[529] East Texas Cooperatives request that the Commission define the scope of acceptable benefits that may be considered, provide that cost allocation methods ensure that customers receive benefits commensurate with their share of costs, and conclude that participant funding is a failed cost allocation method.

717. Several commenters agree that the Commission should clarify what regional cost

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[528] *E.g.*, AWEA; East Texas Cooperatives; Gaelectric; ITC Companies; Multiparty Commenters; NextEra; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; and WIRES.

[529] *E.g.*, AWEA; Gaelectric; Multiparty Commenters; and Transmission Dependent Utility Systems.

allocation approaches are not acceptable.[530] AWEA states that to ensure that future cost allocation proposals do not serve as barriers to transmission expansion, and can support transmission additions that are "right sized" to meet the long-term needs of the system, the Commission should specify when participant funding, and other such cost allocation methods, should not be allowed, or what level of participant funding it might find acceptable. NextEra argues that the use of participant funding should be minimized, and that the Final Rule should specify that costs of transmission projects identified through the transmission planning process cannot be allocated to generators because any other outcome would simply continue the status quo of discouraging development of new resources.

718. In contrast, other commenters argue that the Commission should promote flexibility, and continue to allow for participant funding of projects with voluntary agreements on cost sharing.[531] Some commenters appear to believe the Proposed Rule would prohibit the use of participant funding in all circumstances, not just for new

[530] *E.g.*, AWEA; ITC Companies; Multiparty Commenters; NextEra; and WIRES.

[531] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; Arizona Public Service Company; City of Los Angeles Department of Water and Power; Santa Clara; E.ON; Large Public Power Council; Nebraska Public Power District; Northern Tier Transmission Group; Salt River Project; Transmission Agency of Northern California; Tucson Electric; Washington Utilities and Transportation Commission; WestConnect; and Westar.

transmission facilities in a regional transmission plan for purposes of regional cost allocation to regional beneficiaries. As a starting point, a few commenters state that the Commission has accepted and continues to accept rates using participant funding. For example, E.ON points out that the Commission approved negotiated rates for the Chinook and Zephyr merchant transmission projects, which it believes is evidence that participant funding may be of practical use and may have more widespread application as transmission customers are required to access electricity from renewable generation. Therefore, some commenters argue that the Commission first must present factual evidence that current cost allocation methods are unjust and unreasonable, or otherwise unduly discriminatory, which it has not done. Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission argue that participant funding most closely follows "but for" cost causation principles, and Ad Hoc Coalition of Southeastern Utilities adds that it is most consistent with judicial precedent regarding what constitutes an appropriate cost allocation method. Similarly, many commenters contend that the participant funding approach has led to the building of transmission projects that meet the reliability and economic needs of customers, and state and local policy goals.[532] Ad Hoc Coalition of Southeastern Utilities emphasizes that a requestor pays approach has been the norm for intersystem transmission projects in both the electric and gas industries. Arizona

[532] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; City of Los Angeles Department of Water and Power; and Tucson Electric.

Corporation Commission, Salt River Project, City of Los Angeles Department of Water and Power, and Tucson Electric state that, in the West and Southwest, the participant-funded method of cost allocation has not delayed construction of transmission facilities and has been effective. Northern Tier Transmission Group believes that facilitating willing parties to make rational business decisions has a higher probability of causing the construction of new transmission than does a situation where costs could be forced upon unwilling parties, as is contemplated by the Proposed Rule.

719. In its reply comments, Entergy states that it believes that participant funding is an appropriate pricing method and should not be excluded from consideration in the Final Rule. Entergy requests clarification that any adverse finding against participant funding would not apply to customer-specific requests for service under the *pro forma* OATT. It notes that the Commission provided this clarification in Order No. 890, and it suggests that the Commission had the same intent in the Proposed Rule. Entergy argues that the types of projects set forth in the Proposed Rule do not include customer-specific requests for service, and it explains that such requests are evaluated pursuant to specific OATT procedures that govern system impact and facilities studies, and are performed in consultation with the affected customer, not vetted through a regional stakeholder process. Entergy notes that upgrades necessary to meet the specific request are similarly constructed to meet the needs of the customers, and are not subjected to a cost-benefit test to identify beneficiaries. Entergy cites to its own proposal regarding customer-specific

service requests that the Commission found "will promote, not discourage, efficient investments."[533]

720. Some commenters that support participant funding as a cost allocation method raise concerns about overly broad socialization of costs absent such a mechanism.[534] Large Public Power Council adds that the potential for cost socialization will lead to the planning process becoming vastly more contentious. Southern Companies argue that the proposed reforms are not consistent with cost causation principles. Likewise, Transmission Agency of Northern California argues that broad socialization of costs among all transmission customers is inconsistent with cost causation principles. Avista and Puget Sound state that the cost allocation proposals appear to improperly shift costs to existing customers that do not participate in projects. American Forest & Paper is concerned about the potential for overly broad socialization of costs to diminish incentives for cost-effective planning.

721. Some commenters believe that existing participant funding cost allocation processes are adequate and do not see a need at this time to change those existing processes.[535] These commenters and others,[536] primarily located in the Western

[533] *Entergy Servs., Inc.*, 115 FERC ¶ 61,095, at P 168 (2006).

[534] *E.g.*, Arizona Public Service Company; Large Public Power Council; Nebraska Public Power District; WestConnect; and Transmission Agency of Northern California.

[535] *E.g.*, WestConnect; PUC of Nevada; Transmission Agency of Northern

(continued…)

Interconnection, believe that voluntary coordination and cost allocation of transmission facilities are more appropriate, particularly given their experiences, and that a mandatory cost allocation requirement could impede the transmission planning process and unintentionally delay or impede the development of new transmission.[537] California Commissions contend that this voluntary approach has minimized disputes and litigation. Arizona Public Service Company, Tucson Electric, and others suggest that voluntary participant funding of projects has permitted participants to successfully engage in allocating costs for transmission projects in the Southwest.

722. Commenters note other challenges to restricting participant funding. For example, California Commissions explain that assessment of benefits and beneficiaries is particularly challenging for long distance interregional transmission that would access remote renewable resources, given the uncertainties surrounding the ultimate build-out, cost (and cost competitiveness), and long-term purchasers for these resources, which are greatly complicated by the fact that energy and renewable energy credits may be purchased separately. Xcel states that MISO included a proposed solution to the "first move/free rider" issue, namely, that a generator interconnection customer who funds

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California; and Coalition for Fair Transmission Policy.

[536] *E.g.*, Arizona Public Service Company; Bonneville Power; Tucson Electric; and California Transmission Planning Group.

[537] *E.g.*, Arizona Public Service Company; California Commissions; and Western Area Power Administration.

network upgrades pays the entire cost of those upgrades, regardless of other parties who may use them. Xcel asks that the Commission encourage such flexible and innovative solutions to such issues, particularly as public policy requirements are incorporated into transmission planning processes.

**c. Commission Determination**

723. The Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method. If proposed as a regional or interregional cost allocation method, participant funding will not comply with the regional or interregional cost allocation principles adopted above. The Commission is concerned that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. Because of this, it is likely that some transmission facilities identified as needed in the regional transmission planning process would not be constructed in a timely manner, adversely affecting ratepayers. On the other hand, we agree that if the costs of a transmission facility were to be allocated to non-beneficiaries of that transmission facility, then those non-beneficiaries are likely to oppose selection of the transmission facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the transmission facility's construction. For this reason, we adopt the cost allocation principles above that seek, among other things, to ensure that any regional

cost allocation method or methods developed in compliance with this Final Rule allocates costs roughly commensurate with benefits.

724. We therefore disagree with commenters who challenge this Final Rule's limitation on the use of participant funding on the grounds that it is inconsistent with the cost causation principle. Through the cost allocation principles adopted above, we require in all cases that regional and interregional cost allocation methods result in the allocation of costs for new transmission facilities in a manner that is roughly commensurate with the benefits received by those who will pay those costs. In proposing any cost allocation method or methods on compliance, there must be a demonstrated link between the costs imposed through a cost allocation method and the benefits received by beneficiaries that must pay those costs. However, these principles do not in any way foreclose the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility. Indeed, the evaluation of the potential benefits and beneficiaries of a proposed transmission facility may facilitate negotiations among such entities, potentially leading to greater use of participant funding for transmission projects not selected in the regional transmission plan for purposes of cost allocation.

725. Thus, we will not permit participant funding to be the cost allocation method for regional or interregional projects that are selected in a regional transmission plan for

purposes of cost allocation. However, we are not finding that participant funding leads to improper results in all cases. For example, a transmission developer may propose a project to be selected in the regional transmission plan for purposes of regional cost allocation but fail to satisfy the transmission planning region's criteria for a transmission project selected in the regional transmission plan for purposes of cost allocation. Under such circumstances, the developer could either withdraw its transmission project or proceed to "participant fund" the transmission project on its own or jointly with others. In addition, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding.

726. Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission have not shown why participant funding is uniquely the cost allocation method that most closely follows "but for" cost causation principles. In fact, established precedent argues against this claim. Cost causation principles specify that, "[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred [because] without the expectation of its contributions, the facilities might not have been built, or might have been delayed."[538] This statement embodies "but for" reasoning, and since participant funding does not in all cases capture all beneficiaries

[538] *Illinois Commerce Commission*, 576 F.3d 470 at 476.

of new facilities, it cannot be said to be the cost allocation method that mostly follows "but for" cost causation principles.[539] Northern Tier Transmission Group argues that participant funding has a higher probability of causing the construction of new transmission facilities because it relies on willing parties and does not involve parties who are unwilling to bear costs and who will engage in litigation to oppose transmission project development. Yet nothing in this Final Rule precludes the use of participant funding for those transmission projects with the support of individual market participants. We find that Northern Tier Transmission Group's argument that other cost allocation methods will impair construction to be speculative and see no reason to conclude that other methods in fact will have this result.

727. In response to Transmission Agency of Northern California, Avista, and Puget Sound, we note that a limitation on participant funding is far from a mandate for broad cost socialization. There is nothing in our cost allocation reforms that requires broad socialization or supports improper cost shifting in violation of cost causation principles.

As discussed fully above, our cost allocation principles require that costs be allocated roughly commensurate with the benefits received by those that pay those costs.

[539] We discuss Ad Hoc Coalition of Southeastern Utilities' claim regarding the consistency of participant funding with judicial precedent on cost allocation methods below in section IV.F.2.

728. In any event, nothing in this Final Rule applies to existing transmission facilities with existing cost allocations or to transmission projects currently under development.[540]

729. In response to Entergy's request, we clarify that our cost allocation reforms in this Final Rule are not intended to modify existing *pro forma* OATT transmission service mechanisms for individual transmission service requests or requests for interconnection service.

### 3. Whether Regional and Interregional Cost Allocation Methods May Differ

#### a. Commission Proposal

730. In the Proposed Rule, the Commission explained that the method used for allocating interregional transmission facility costs between any two transmission planning regions may be different from the method used by the public utility transmission providers located in either of those transmission planning regions to allocate the costs of new regional facilities. Additionally, the Commission proposed that the cost allocation method used by the public utility transmission providers located in a transmission planning region to allocate the costs of new regional facilities could be different from the cost allocation method by which the public utility transmission providers in the same transmission planning region further allocate costs to be borne by that transmission planning region pursuant to an agreed-upon method for allocating the costs of

[540] *See also* discussion *supra* section III.A.3.

interregional facilities.[541]

**b. Comments**

731. Several commenters agree with the Commission's proposal that the method used for allocating interregional transmission facility costs may differ from the method used to allocate regional costs.[542] Georgia Transmission Corporation states that if an interregional coordination obligation would require entities to enter into agreements with neighboring regions, the Commission should specify that it would not require the transmission entity to accept the neighboring entity's cost allocation method. Indianapolis Power & Light states that the cost allocation provisions of an interregional coordination agreement should set forth how costs are divided between the regions and leave it up to the regions to determine how their shares are divided among their subregions/zones/customers. MISO Transmission Owners state that transmission providers and their stakeholders should be permitted to determine whether the cost allocation methods used for regional projects should apply to the transmission provider's share of interregional facilities.

732. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. It also states that the

[541] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 176.

[542] *E.g.*, Georgia Transmission Corporation; Indianapolis Power & Light; MISO Transmission Owners; NEPOOL; and Northeast Utilities.

Final Rule should either clarify the manner in which agreement on a cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

### c. Commission Determination

733. We find that the method or methods for interregional cost allocation used by two transmission planning regions may be different from the method or methods used by either of them for regional cost allocation. Also, the method or methods for allocating a region's share of the cost of an interregional transmission facility may differ from the method or methods for allocating the cost of a regional facility within that region.

734. Although the public utility transmission providers in a transmission planning region may choose to allocate their share of the costs of an interregional transmission facility using their regional cost allocation method or methods, we see no reason to require them to do so. Indeed, for a transmission planning region that shares the cost of regional transmission facilities broadly, it may be inappropriate to apply broad cost sharing for an interregional transmission facility that is found to benefit only part of that transmission planning region. In addition, an interregional transmission facility may be of such greater scale than most regional transmission facilities that it may result in different types of benefits and beneficiaries than for a regional transmission facility.

735. In response to Georgia Transmission Corporation, we clarify that we do not require the public utility transmission providers in a transmission planning region to accept the regional transmission planning method or methods of another transmission planning region with which it participates regarding interregional transmission coordination. Each transmission planning region would determine for itself how to allocate the costs of a new interregional transmission facility consistent with this Final Rule.

#### 4. Recommendations for Additional Commission Guidance on the Application of the Transmission Cost Allocation Principles

736. Several comments recommend that the Commission provide additional guidance on how to apply the cost allocation principles.

##### a. Comments

737. A number of commenters provide additional suggestions on cost allocation methods. Duke states that without clear pricing guidelines that do more than restate general cost allocation principles, regional and interregional transmission projects will have trouble getting out of the starting gate. Pennsylvania PUC asserts that cost allocation principles and methods should be reasonably clear and explainable to all stakeholders so that development of a cost allocation paradigm can be effectively grasped by all participants. East Texas Cooperatives believe that the costs of all transmission facilities needed to maintain reliability or to deliver long-term resources to load serving entities should be rolled into the applicable zonal, regional, or interregional rate, and that

individual cost allocation methods should clearly set forth a plan for identifying beneficiaries and allocating costs to them. Washington Utilities and Transportation Commission is concerned that necessary certainty on cost allocation would not be achieved if the Final Rule lacks detail on the standards to be applied when reviewing or approving cost allocations proposals and the Commission opts to develop more precise cost allocation policies on a case-by-case basis.

738. Federal Trade Commission encourages the Commission to consider providing stronger guidance regarding transmission cost allocation principles. It expresses its concern that unnecessary variance in allocation methods will have a disruptive effect on multi-area transmission proposals, akin to the disruptive effects that unnecessary diversity in methods for calculating available transmission capacity had on transmission services spanning multiple areas. Federal Trade Commission encourages the Commission to consider whether stronger guidance would promote consensus sooner and avoid creating a patchwork of transmission cost allocation methods that may not support broad, efficient regional markets and low-cost compliance with environmental and energy security policy initiatives.

739. WIRES states that, as proposed, the principles provide only the most general outer bounds of acceptable practice and do not specify the characteristics of cost allocation methods that the Commission is likely to consider just and reasonable. WIRES states that the use of a relatively complete set of principles affords the Commission an

opportunity to help short-cut the endless debates about limited merits of participant funding in a network environment and about the extent to which the benefits of transmission can be quantified in specific instances.

740. Northwestern Corporation (Montana) asserts that new transmission lines should not be insulated from sharing a portion of the network costs and/or an allocation of the network revenue requirement because new transmission lines experience enhanced reliability by connecting to the network transmission system.

741. Illinois Commerce Commission urges the Commission to remove "postage stamp" cost allocation from the list of acceptable cost allocation methods.[543] It maintains that postage stamp cost allocation is highly unlikely to produce just, reasonable, and nondiscriminatory rates, and continuing to maintain it as a possible cost allocation method is paralyzing transmission expansion.

742. Other commenters make suggestions or requests for guidance that are similar to other commenters' recommendations for additional cost allocation principles discussed above. For example, some commenters suggest that cost allocation methods should be periodically recalculated or reevaluated. Many commenters believe that changes to transmission system topology and amendments to state policies could alter disbursement

[543] "Postage stamp" here refers to regionwide allocation of the cost of a transmission facility.

of benefits, so the Final Rule should require cost allocations to be periodically reviewed and recalculated.[544] Some of these commenters believe that permanent cost allocations may inhibit investing in transmission upgrades and that there should be periodic reassessments to address any unintended consequences.[545] For example, E.ON and East Texas Cooperatives suggest that cost allocation reevaluation should occur every five years. Pennsylvania PUC states that a cost allocation method should be designed to evolve and reflect system changes over time.

743. Ohio Consumers Counsel and West Virginia Consumer Advocate Division suggest that the Commission adopt a process that allows for expedited resolution of disputes over cost allocation that may arise during the regional planning process. ISO New England recommends Commission-sponsored mediation or other alternative dispute resolution for interregional cost allocation to assist two regions on reaching agreement if they cannot do so.

744. Commenters also submitted comments suggesting multiple ways to allocate costs

[544] *E.g.*, Sunflower and Mid-Kansas; Electricity Consumers Resource Council and Associated Industrial Groups; PUC of Ohio; East Texas Cooperatives; E.ON; and Transmission Dependent Utility Systems.

[545] *E.g.*, Transmission Dependent Utility Systems; Sunflower and Mid-Kansas; E.ON; East Texas Cooperatives; and Massachusetts Municipal and New Hampshire Electric.

of public policy driven projects.[546] FirstEnergy Service Company believes the Commission should clarify that the cost causation principle, including the requirement that costs are at least roughly commensurate with benefits, applies with full force to public policy driven projects in the regional planning process. First Wind believes the Commission should seek state input and rely upon state judgment on cost allocation for projects flowing from state policy. NEPOOL and New England States Committee on Electricity believe that each region should have considerable flexibility to develop public policy cost allocations. Transmission Dependent Utility Systems notes that not all projects proposed to implement public policy are worthy of presumptive acceptance and should be rigorously scrutinized in the stakeholder process.

### b. Commission Determination

745. The Commission appreciates interested commenters' views, suggestions and requests for additional Commission guidance regarding the development of an acceptable cost allocation method or methods to comply with the identified cost allocation principles for new regional and interregional transmission facilities. We believe, however, that the principles adopted in this Final Rule provide sufficient general guidance for public utility transmission providers. The principles establish threshold criteria for a cost allocation

[546] *E.g.*, FirstEnergy Service Company; First Wind; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Public Power Council; and Transmission Dependent Utility Systems.

method or methods to facilitate the development of a just and reasonable and not unduly discriminatory or preferential cost allocation method or methods. Additionally, the principles afford public utility transmission providers in individual transmission planning regions the flexibility necessary to accommodate unique regional characteristics. The Commission is concerned that providing the additional guidance or limitations requested by commenters would unduly restrict this flexibility. As we explained above, the Commission recognizes the need for regions to retain some level of flexibility to account for specific regional characteristics, resource types, or policy mandates.

746. We emphasize, however, that any variations between regions must be consistent with the six cost allocation principles. For example, East Texas Cooperatives suggest periodic reevaluation of cost allocation methods to respond to system changes. We do not view such a proposal as inconsistent with the cost allocation principles adopted above and, as such, it could be presented and evaluated at the regional level and, if agreed upon, proposed to be implemented by that transmission planning region. However, the Commission declines to prescribe such a policy for all transmission planning regions nationwide.

747. With respect to comments regarding how to allocate costs for public policy driven transmission projects, as discussed above,[547] we are not requiring public utility

[547] *See* discussion *supra* section III.E.7.

transmission providers to use the same cost allocation method for public policy and other types of transmission facilities. Instead, as discussed for Cost Allocation Principle 6, we permit different regional and interregional cost allocation methods for different types of transmission projects. Thus, whether each region or pair of transmission planning regions has a separate cost allocation method for public policy driven transmission projects depends on the consensus within that transmission planning region or those transmission planning regions, and we will not prescribe a uniform method for such transmission projects.

748. In response to Illinois Commerce Commission, the Commission declines to find in advance that a "postage stamp" cost allocation may not be an acceptable cost allocation method. If public utility transmission providers in a region, in consultation with their stakeholders, agree to such a method, and it is demonstrated to be consistent with the cost allocation principles and is supported with an appropriate assessment of benefits, then such an allocation may be submitted to the Commission on compliance, and the Commission will determine then whether the method meets its requirements.

749. We also clarify that, by establishing the six principles for regional and interregional cost allocation, the Commission is not attempting to supersede the cost causation principle. Rather, these six principles serve as guidelines for public utility transmission providers to use to create cost allocation methods that are consistent with the cost causation principle.

750. With regard to the concerns of Ohio Consumers' Counsel, West Virginia Consumer Advocate Division, and ISO New England about dispute resolution, the Commission believes that the dispute resolution processes in place under Order No. 890, enhanced as may be necessary to comply with our transmission planning reforms, will be adequate to address in the first instance, any disagreements that may arise regarding the allocation of transmission costs. The Commission reviewed and approved all of the dispute resolution procedures currently in place during our review of the compliance filings in response to Order No. 890, requiring enhancements in a number of cases.[548] We will review any changes to those dispute resolution procedures in response to compliance filings submitted in response to this Final Rule.

### G. Cost Allocation Matters Related to Other Commission Rules, Joint Ownership, and Non-Transmission Alternatives

751. Commenters also raised cost allocation issues related to generator interconnection costs in Order No. 2003,[549] pancaked transmission rates policy in Order No. 2000,[550]

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[548] *See, e.g.*, *Idaho Power Co.*, 128 FERC ¶ 61,064 at P 30-40; *Duke Energy Carolinas, LLC*, 127 FERC ¶ 61,281, at P 38-41 (2009); *New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,068, at P 61-64 (2008).

[549] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 FR 49846 (Aug. 18, 2003), FERC Stats. & Regs. ¶ 31,146, at P 676 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*,

(continued…)

transmission rate incentives in Order No. 679,[551] the relationship of this proceeding to the proceeding on variable energy resources, Docket No. RM10-11-000, and joint transmission ownership.

### 1. Whether To Reform Cost Allocation for Generator Interconnections

752. In the Proposed Rule, the Commission did not propose to alter the cost recovery provisions of its generator interconnection rules.

#### a. Comments

753. Several commenters address the interaction between Order No. 2003 and the cost allocation requirements of this Final Rule. For example, Duke seeks clarification that impacts on transmission owners in neighboring regions resulting from a specific generator interconnection or transmission service request will continue to be addressed under the existing generation or transmission interconnection arrangements. East Texas Cooperatives urge the Commission to require development of an integrated process for

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552 U.S. 1230 (2008).

[550] *Regional Transmission Organizations*, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[551] Order No. 679, 71 FR 43294, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, 72 FR 1152, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062.

studying network and point-to-point transmission service requests and generator interconnection requests that affect neighboring regions.

754. Other commenters address the interaction between Order No. 2003 and the transmission planning requirements. For instance, Solar Energy Industries and Large-scale Solar state that the Commission should require transmission providers to coordinate the transmission planning study process with the generator interconnection study process. PPL Companies agree stating that this would ensure that interconnection customers and native load bear their fair share of the costs of new transmission. On the other hand, NextEra believes that the costs of transmission projects identified through the transmission planning process should not be allocated to generators.

755. Some commenters urge the Commission to reevaluate the cost responsibilities in Order No. 2003 because they believe these are being used to circumvent the transmission planning process, creating a situation where load serving entities are forced to finance projects without project beneficiaries being identified.[552] If this continues, Bay Area Municipal Transmission Group asserts that greater transparency in the interconnection process is needed to facilitate the determination of the most cost-effective interconnection alternative. California Municipal Utilities argue that, if the costs of network upgrades

[552] *E.g.*, Bay Area Municipal Transmission Group; California Municipal Utilities; and City of Santa Clara.

identified through generator interconnection studies are borne by load within a region, those upgrades should be examined by the regional transmission planning process as a necessary precondition to approval by the relevant transmission provider. Six Cities note that the California ISO had represented in an Order No. 890 compliance filing that all interconnection-related network upgrades would be submitted through the request window open in each planning cycle and evaluated in the transmission planning process. Northern California Power Agency asserts that the generator interconnection process includes a loophole whereby transmission providers can circumvent the transmission planning process by proposing individual projects that are constructed by transmission providers, and recommends that the Commission limit

the use of interconnection-related upgrades by ensuring they are a cost-effective means of grid expansion.

756. Several commenters discuss cost allocation for generation interconnection in the context of public policy projects. For example, Imperial Irrigation District asks the Commission to clarify that generation interconnection customers and their off-takers can be allocated the costs of public policy projects under the principles developed by transmission providers in each region when those generation project developers and their off-takers cause the need for or benefit from the public policy projects. In its reply comments, City of Santa Clara agrees with Imperial Irrigation District. Old Dominion

agrees with PJM that greater clarity is needed regarding the extent to which the Commission is proposing that cost allocation for public policy driven projects depart from the existing Order No. 2003 framework. Old Dominion recommends that the Commission require all transmission providers to describe in their respective transmission planning and cost allocation tariff filings specific rules governing cost allocation for such projects.

757. East Texas Cooperatives state that they support a cost allocation policy under which the costs of network upgrades required to serve the native load of a transmission provider's network customers are rolled into the transmission provider's rates. They recommend that if a network upgrade is needed to accommodate an interconnection request for a generating facility that has not been designated as a network resource or is not otherwise contractually committed to serve customers within the transmission provider's footprint on a long-term basis, the interconnecting customer should be required to pay for the cost of network upgrades that would not have been required but for the interconnection request. They state that applying this policy would provide a level of assurance that the cost of such facilities will be allocated roughly commensurate to the estimated benefits.

758. Northern Tier Transmission Group asserts that, if a transmission provider does not execute an interconnection agreement with a generator, then the transmission provider has no mechanism to assess costs upon the generator. Northern Tier Transmission Group

states that, to the extent the Commission chooses to address this practical issue, it should be done in the context of the generator interconnection procedures and agreements and not in the context of transmission planning.

759. In response, California ISO argues that such suggestions are beyond the scope of this proceeding and, if the Commission wishes to overhaul Order No. 2003, it should do so in a separate rulemaking so that parties have adequate notice that the Commission is proposing to modify its *pro forma* large generator interconnection procedures. Replying to Six Cities, California ISO argues that their assertion is based on a misconception that interconnection-related network upgrades need to be approved through the transmission planning process. California ISO states that Order No. 890 did not apply to such network upgrades.

### b. Commission Determination

760. The Commission agrees with the California ISO and other commenters that issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking. Order No. 2003 sets forth the procedures for the interconnection of a large generating transmission facility to the bulk power system. This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities. Therefore, this Final Rule is not the proper proceeding for commenters to raise issues about the

interconnection agreements and procedures under Order Nos. 2003,[553] 2006[554] or 661.[555] However, in not addressing these issues here, we are not minimizing the importance of evaluating the impact of generation interconnection requests during transmission planning, nor limiting the ability of public utility transmission providers to use requests for generator interconnections in developing assumptions to be used in the transmission planning process.

### 2. Pancaked Rates

#### a. Comments

761. A few commenters ask the Commission to address the pancaking of rates within transmission planning regions. Transmission Dependent Utility Systems assert that the Proposed Rule should eliminate regional rate pancaking as it remains a significant financial dilemma for many transmission customers and is destructive to regional

[553] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g*, Order No. 2003-A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g*, Order No. 2003-C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190 , *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[554] Order No. 2006, 70 FR 34189, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No. 2006-A, 70 FR 71760, FERC Stats. & Regs. ¶ 31,196, *order granting clarification*, Order No. 2006-B, 71 FR 42587, FERC Stats. & Regs. ¶ 31,221.

[555] Order No. 661, 70 FR 34993 (Jun. 16, 2005), FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198.

planning. Transmission Dependent Utility Systems submit that if the Commission is going to implement a requirement for regional cost allocation, it should, at a minimum, eliminate pancaked rates unless there is an existing regional cost allocation method in place.

762. Sunflower and Mid-Kansas, on the other hand, contend that the Commission should modify its "no pancaking" policies for an RTO or ISO because the policy is not appropriate for large interregional projects and will potentially create extremely high rate increases for customers.

763. Gaelectric North America explains that merchant transmission developers are creating new pancaked rates. It asserts that, as public utilities construct radial merchant lines and allocate their costs through participant funding, they are creating additional pancaked rates for new generation owners who may wish to utilize these new facilities. Gaelectric North America argues that such pancaked rates inhibit the development and use of renewable resources. Further, it states that stringing radial transmission over network facilities is inefficient and pursued only to avoid appropriate cost allocation.

### b. Commission Determination

764. We decline to make new findings with respect to pancaked rates in this Final Rule as it is beyond the scope of this proceeding. In particular, we do not make any modifications to the Commission's pancaked rate provisions for an RTO under Order No. 2000. If rate pancaking is an issue in a particular transmission planning region,

stakeholders may raise their concerns in the consultations leading to the compliance proceedings for this Final Rule or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.

### 3. Transmission Rate Incentives

765. In the Proposed Rule, the Commission did not propose to alter its transmission rate incentive policies of Order No. 679.

#### a. Comments

766. Some commenters suggest that the Commission revisit its policy on transmission rate incentives, as set forth in Order No. 679. For example, they relate the Commission's proposals regarding nonincumbent transmission developers to transmission rate incentives.[556] Transmission Access Policy Study Group suggests that the Commission could require an incumbent transmission provider that exercises a federal right of first refusal to own and build a transmission facility to forgo any incentives on that facility. It argues that an incumbent transmission owner that exercises a federal right of first refusal should not then be given an incentive as necessary to encourage it to construct needed transmission. Minnesota Public Utilities Commission and Minnesota Office of Energy Security believe that one reason a federal right of first refusal may be justified is because there are instances where an incumbent transmission provider's rate of return is

[556] *E.g.*, New England States Committee on Electricity; Transmission Access Policy Study Group; and Southern California Edison.

significantly lower than the incentive rate of return the Commission has approved for nonincumbent transmission developers. ITC Companies replies that such instances only demonstrate that different transmission incentives have been awarded in different cases by different regulatory bodies, noting that there are a variety of approved utility ROEs across the industry.

767. Other commenters tie the Commission's cost allocation proposals to transmission rate incentives. For example, APPA states that there is a clear causal connection between thorny cost allocation concerns and the Commission's incentive policy. APPA argues that when excessive transmission rate incentives are awarded to project sponsors, no one benefits from the associated costs except for the sponsors. Transmission Access Policy Study Group also suggests that the Commission use this opportunity to reevaluate application of Order No. 679 so that it does not add burdens on the economy or make siting and cost allocation issues more difficult than they already are. Transmission Dependent Utility Systems also state that transmission providers should be able to recover only the costs associated with a major transmission project through formula rates if that project was a product of an Order No. 890-compliant planning process that also meets the requirements of the Final Rule.

768. Joint Commenters recite cases in which project developers have been granted rate incentives that they believe substantially exceed the incentives that would result in just and reasonable rates. Joint Commenters also assert that the Commission has failed to

recognize that the financial ground has shifted, citing the recent recession, historically low interest rates, and high unemployment. According to Joint Commenters, the rate of return needed to attract investment in a long-lived asset used to provide monopoly service is less than it was a few years ago. Finally, Joint Commenters recommend that the Commission revisit two features of its 1992 incentive rate policy statement,[557] concerning the requirement that incentive rate mechanisms be symmetrical and the requirement that applicants quantify the benefits to ratepayers as the incentive payment is awarded, arguing that these principles are equally important today. In its reply comments, Illinois Commerce Commission generally agrees with Joint Commenters, as does Organization of MISO States.

769. Pacific Gas & Electric recommends that the Commission clearly signal in the Final Rule that rate incentives are available for utilities that dedicate resources to the successful development of needed regional projects. In particular, Pacific Gas & Electric suggests that incentives for partnership in the development of major backbone projects crossing multiple jurisdictions are appropriate. Pacific Gas & Electric suggests that incentives should be offered for partnerships to both independent transmission companies and incumbent utilities, and that the incentives should be conditioned upon establishment of development arrangements that ensure consistent design standards are used that are

[557] *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities*, 61 FERC ¶ 61,168 (1992).

compatible with the incumbent system, ongoing coordination of maintenance arrangements by responsible entities, and proper bilateral interconnection or coordinated operation agreements that will ensure the continuity and sustained reliability of the system.

770. However, a number of commenters oppose calls to reopen Order No. 679 in this proceeding.[558] Several commenters argue that such comments are beyond the scope of this rulemaking. They note that Order No. 679 was implemented in response to the direction of Congress, codified in section 219 of the FPA, to incent transmission investment. Some commenters note that Order No. 679 does not undermine transmission planning and cost allocation processes because the grant of incentives is conditioned on approval of the project under the relevant regional transmission planning processes. APPA states that it opposes blanket statements supporting the applicability of incentives under Order No. 679, and notes that Pacific Gas & Electric's request is illuminating because it shows how accustomed investor-owned utilities have become to obtaining such incentives and how they assume the Commission will simply rubber stamp in advance their requests for more incentives.

### b. Commission Determination

771. We acknowledge commenters concerns regarding the Commission's policy on

[558] *E.g.*, AEP; Edison Electric Institute; EIF Management; ITC Companies; National Grid; Pacific Gas & Electric; and PSEG Companies.

transmission rate incentives under Order No. 679. However, we decline to revisit or modify our policy under Order No. 679 in this Final Rule, as it is beyond the scope of this proceeding.[559]

#### 4. Relationship of This Proceeding to the Proceeding on Variable Energy Resources

##### a. Comments

772. APPA argues that, contrary to the Commission's decision not to address transmission planning and cost allocation issues in its proceeding on the integration of variable energy resources (VER), Docket No. RM10-11-000, it believes that the two issues are not easy to compartmentalize. According to APPA, effective integration of VERs into regional transmission systems depends in large part on the availability of transmission facilities to support such integration, which in turn raises the issue of who will pay for the additional transmission facilities needed to undertake this integration effort. Thus, APPA urges the Commission to consider the tariff modification issues raised by VERs integration together with the need to develop cost allocation methods to pay for the additional transmission facilities that such integration requires.[560]

773. In its reply comments, Exelon argues that the Commission should address in this

[559] The Commission issued a Notice of Inquiry on May 19, 2011 regarding its policy on transmission incentives under Order No. 679. *See Promoting Transmission Investment Through Pricing Reform*, Notice of Inquiry, 135 FERC ¶ 61,146 (2011).

[560] APPA also incorporates by reference the comments it submitted in Docket No. RM10-11-000.

proceeding the operational issues entailed in integrating large amounts of VERs onto the grid in tandem with its rules for transmission planning and cost allocation. It states that whether or not the Commission issues a single rule in these dockets, it should rely on the record developed in the VERs rulemaking proceeding in deciding the Final Rule here, arguing that the record in the VERs proceeding fully supports the Commission requiring full accounting for the costs of integrating wind and other variable resources.

#### b. Commission Determination

774. This Final Rule establishes minimum requirements to guide the affected entities in developing their own transmission planning processes and cost allocation methods, which then will be submitted for filing with the Commission. The requirements established by this Final Rule apply to transmission planning and cost allocation for all resources. The VERs proceeding, however, addresses operational issues. To the extent that entities consider it necessary or appropriate to consider such operational issues in this Final Rule, they may do so by making a separate section 205 filing rather than raise issues on compliance in this proceeding.

### 5. Joint Ownership

#### a. Comments

775. A number of commenters urge the Commission to consider joint transmission ownership as a financing and cost allocation tool within the Proposed Rule. APPA and Six Cities ask the Commission to promulgate a rule favoring joint transmission

ownership and to require that eligibility for rate incentives depend on an applicant's showing that it has offered reasonable opportunities for joint transmission ownership. APPA asserts that joint ownership diversifies financial risks and reduces the overall costs of the project as well as the need for transmission incentives. Transmission Access Policy Study Group and Transmission Agency of Northern California state that joint ownership leads to a more collaborative process in planning and development for both pooled systems and load serving entities. Transmission Access Policy Study Group states that joint ownership results in more diverse generation scenarios, shorter permitting processes during siting, and simpler resolutions of cost allocation issues, and points out that joint ownership spreads the risk of projects and provides a variety of sources of capital for projects.

**b. Commission Determination**

776. Specific financing techniques such as joint ownership are beyond the scope of this proceeding. Transmission developers are, of course, free to consider joint ownership when proposing and developing a transmission project. Just as we are not requiring any specific cost allocation method, we do not specifically address joint ownership as a cost allocation tool in this proceeding. However, we reiterate here our statement in Order No. 890 that we believe there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the

transmission grid by transmission customers.[561]

### 6. Cost Recovery for Non-Transmission Alternatives

#### a. Comment Summary

777. GridSolar suggests that the Commission require utilities and RTOs/ISOs to evaluate alternatives to traditional transmission solutions on the same basis, using the same standards as those used for traditional transmission solutions, and that this could be done through a competitive solicitation. GridSolar notes that distributed energy resources connect at voltages below 69 kV and therefore do not qualify for cost allocation treatment under the transmission planning process although they provide the same services as other transmission resources. Similarly, 26 Public Interest Organizations argue that transmission and non-transmission solutions should be treated comparably for cost recovery purposes.

778. FirstEnergy Service Company argues that while the Proposed Rule does not address cost recovery for non-transmission projects, only the costs of facilities that perform a transmission function (including energy storage projects) should be included in transmission rates. FirstEnergy Service Company argues that regional transmission planning processes should not be a vehicle for owners of generation or demand side

[561] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 593.

management projects that are eligible to earn revenue from sales of energy, capacity, and ancillary services to earn subsidies from transmission customers.

**b. Commission Determination**

779. As we make clear above in the section on Regional Transmission Planning, we are maintaining the approach taken in Order No. 890 and will require that generation, demand resources, and transmission be treated comparably in the regional transmission planning process.[562] However, while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, we conclude that the issue of cost recovery for non-transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities.[563]

[562] *See* discussion *supra* Section III.A.

[563] As we stated in the Proposed Rule, the Commission has recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes. *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 (citing *Western Grid Development, LLC*, 130 FERC ¶ 61,056 (2010)).

## V. Compliance and Reciprocity Requirements

### A. Compliance

#### 1. Commission Proposal

780. With the exception of the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within six months of the effective date of the Final Rule in this proceeding. With regard to the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within one year of the effective date of the Final Rule in this proceeding.[564] The Commission proposed that it would assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of the Proposed Rule.

#### 2. Comments

781. Exelon urges the Commission to adhere to its original time schedule for compliance filings of six months for intraregional transmission planning and one year for interregional agreements. In its reply comments, LS Power argues that the six-month and

[564] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 179.

twelve-month compliance deadlines are far more generous than the 60-day deadline that the Commission provided for compliance with Order No. 888 and the filing of revised power pooling and multilateral coordination agreements, respectively.

782. Some commenters suggest that the Commission extend the compliance deadlines for up to three years.[565] Indianapolis Power & Light and SPP state that the proposed six-month and one-year deadlines do not allow sufficient time for the stakeholder process. Indianapolis Power & Light states that this is particularly true if the right of first refusal is removed and recommends that the Commission extend the deadlines by a minimum of one year. SPP recommends that the Commission extend the proposed deadline for regional transmission planning by at least six months and for interregional transmission planning and cost allocation to three years. MISO Transmission Owners state that the Commission should extend all compliance deadlines by a minimum of six months. Arizona Corporation Commission states that the Commission should recognize that most public utility transmission providers in the West are not members of an RTO and will need more time, perhaps 24-36 months, to draft regional and interregional transmission plans. Arizona Public Service Company agrees in is reply comments that the compliance deadlines are too aggressive, arguing that the Commission is proposing a vast array of

[565] *E.g.*, Indianapolis Power & Light; SPP; MISO Transmission Owners; Arizona Corporation Commission; and Arizona Public Service Company.

changes that will require utilities to develop positions, collaborate with neighboring utilities, and reach consensus with regional groups.

783. Western Area Power Administration recommends that, in lieu of compliance filings, the Commission require transmission providers to file periodic status reports regarding intraregional and interregional efforts. As an alternative approach, it recommends that the Commission extend the compliance filing deadline to one year for intraregional transmission planning and cost allocation issues and two years for interregional issues. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council recommend that in lieu of the proposed one-year compliance filing requirement, that the Commission call for status updates on these matters in one year's time, potentially to be followed by further orders on a regional basis establishing reasonable timeline targets.

784. Focusing on the six month regional planning compliance deadline, some commenters express the view that six months is a reasonable compliance period.[566] LS Power notes that many of the commenters expressing opposition to the six-month compliance deadline are the same entities that are opposed to removal of the federal right of first refusal, suggesting that any extension of compliance periods not apply to the federal right of first refusal from jurisdictional OATTs and agreements.

[566] *E.g.*, Northwest & Intermountain Power Procedures Coalition and LS Power.

785. Other commenters express concern about the ability of transmission providers to meet the six-month compliance filing requirement for regional transmission planning requirements.[567] New England States Committee on Electricity states that a Final Rule addressing the rights and obligations of nonincumbent transmission providers within the regional planning process should provide the planning regions adequate time to sort through a means of complying. Xcel urges the Commission to allow entities in the Western Interconnection sufficient time and latitude to develop mechanisms that effectively meet the needs of the region; it states that, given the needs of the western region, six months or even one year is an unreasonably short period of time to build a structure to comply with the Commission's regional transmission planning requirements. Washington Utilities and Transportation Commission states that the Commission need not proceed with urgency but should allow existing regional processes to mature, which may lead to a more expeditious and effective transmission planning process.

786. Focusing on the one year interregional compliance deadline, East Texas Cooperatives state that, given the urgent need for interregional transmission planning reform, the Commission should require filing of interregional transmission planning agreements within six months of the effective date of the Final Rule. In its reply comments, East Texas Cooperatives add that shortening this deadline would motivate

[567] *E.g.*, New England States Committee on Electricity and Xcel.

transmission providers to improve coordination with their adjacent regions. Exelon states that for sets of regions that currently have Commission-approved joint operating agreements, the Commission should require a six-month compliance filing.

787. Other commenters contend that the one-year time period for compliance filings relating to interregional transmission planning agreements is unworkable. Southern Companies doubt that an interregional cost allocation agreement could be developed in the Southeast within the proposed one-year deadline. ISO/RTO Council states that this proposal is unworkable due to the complexity, limited resources, the need to involve stakeholders, and potentially the number of agreements to be reached. NV Energy agrees, stating that significant additional time is needed to address interregional transmission agreements and cost allocation issues given the number of parties involved. Xcel agrees that the proposed one-year deadline is unattainable and the Commission should allow more time for interregional planning and cost allocation initiatives to develop voluntarily.

788. Duke and Georgia Transmission Corporation state that the Commission should provide two years to submit interregional transmission planning agreements, given the number of parties that may be involved and the difficulties of developing cost allocation methods. Edison Electric Institute requests that the Commission be flexible regarding compliance deadlines for interregional agreements and cost allocation and consider allowing up to two years for compliance. Pennsylvania PUC states that interregional

agreements will require many actions internal to RTOs and ISOs and planning organizations, therefore the Commission should consider expanding the compliance period from one year to 18 or 24 months.

789. With regard to compliance filings by RTOs and ISOs, New York ISO argues that the Commission should narrow the scope of the compliance filings required under the Final Rule so that RTOs and ISOs are not effectively compelled to demonstrate compliance with requirements that they have already satisfied in their individual Order No. 890 planning proceedings. Several commenters also urge the Commission to consider existing RTO or ISO cost allocation methods as compliant with the proposed cost allocation principles and to avoid reopening debates about regional cost allocation methods already approved by the Commission.[568] Some of these commenters argue that existing processes, such as those used in California ISO and ISO New England, are reasonable[569] while others disagree.[570]

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[568] *E.g.*, California ISO; SoCal Edison; San Diego Gas & Electric; Eastern Mass. Consumer Owned System; Northeast Utilities; MISO; New York ISO; NEPOOL; New England States Committee on Electricity; Kansas Corporation Commission; and Xcel.

[569] *E.g.*, California PUC; Pacific Gas & Electric; NEPOOL; and Connecticut & Rhode Island Commissions.

[570] Several commenters, such as the Integrated Transmission Benefits Model Proponents and Maine Parties argue that ISO New England's current transmission planning and cost allocation methods do not comply with this Final Rule. These concerns should be raised during the stakeholder process used to develop compliance with this Final Rule. To the extent that a commenter believes that its concerns have not

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790. Several commenters state that the Commission should not lightly change existing regional cost allocation methods.[571] For example, Duke states that parties challenging the appropriateness of an existing Commission-approved method should bear a heavy burden of showing why that method is inconsistent with the Final Rule. Transmission Dependent Utility Systems state that the Commission should not automatically disrupt current regional cost allocation methods but instead require compliance filings that demonstrate that the regional cost allocation method was indeed the product of an open and inclusive stakeholder process and that the regional cost allocation method either meets the Commission's proposed cost allocation principles, or that the existing regional cost allocation method is consistent with or superior to the requirement of those principles.

791. Additionally, MISO Transmission Owners, Indianapolis Power & Light, and SPP recommend that the Commission clarify that transmission owners in an RTO or ISO are permitted to participate in the compliance filing of the RTO or ISO without making a separate compliance filing of their own. Omaha Public Power District suggests that providers that are not members of an RTO be allowed to participate in the relevant RTO

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been resolved in the relevant compliance filing, it can raise those concerns at that time in a protest to the compliance filing.

[571] *E.g.*, Duke; New Jersey Board; Northeast Utilities; and Transmission Dependent Utility Systems.

planning process to achieve the interregional planning mandate because this would reduce the cost of coordination and improve its efficiency and effectiveness.

### 3. Commission Determination

792. Given the various comments requesting a longer compliance period, we extend the compliance filing requirements set forth in the Proposed Rule. Accordingly, we find that, with the exception of the requirements with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods, each public utility transmission provider must submit a compliance filing within twelve months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth in this Final Rule.[572] The Commission also requires each public utility transmission provider to submit a compliance filing within eighteen months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth herein with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods. As explained below, we expect that the twelve month and eighteen month deadlines provide sufficient time for each public utility transmission provider to meet the requirements of this Final Rule.

[572] *See* Appendix C for the *pro forma* Attachment K consistent with this Final Rule.

793. For those suggesting that current transmission planning and cost allocation initiatives should be allowed more time to develop, we find that the need to provide rates, terms and conditions of jurisdictional service that are just and reasonable and not unduly discriminatory or preferential, and the need to build new transmission facilities that more efficiently or cost-effectively support the reliable development and operation of wholesale electricity markets, requires that the reforms adopted in this Final Rule are implemented in a timely fashion.[573] The Commission concludes that the time periods provided for adoption of these reforms—twelve months for regional transmission planning and cost allocation reforms and eighteen months for interregional reforms—are reasonable and achievable. These extended time periods provide additional time for public utility transmission providers to work with their stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein.

794. We find that the compliance time periods established in this Final Rule strike an appropriate balance between implementing needed reforms to transmission planning and cost allocation processes in a timely fashion and providing time for those involved in these processes to work with stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein. Moreover, we

[573] This finding is supported by our discussion above in section II.

believe these compliance filing deadlines are compatible with the interests of those that intend to develop transmission planning processes that take into account the lessons learned through the ARRA-funded transmission planning initiatives, discussed above in section I.C and III.C.I, under which the participants of each interconnection are currently collaborating on transmission planning to produce an initial long-term plan in mid-2012 and a final plan in 2013. For this same reason, we are not persuaded by those commenters that recommend that the Commission require periodic status reports in lieu of compliance filings.

795. In response to commenters' requests, we clarify that an RTO or ISO and its public utility transmission provider members may make a compliance filing that demonstrates that some or all of its existing RTO and ISO transmission planning processes are already in compliance with this Final Rule, and we will consider this demonstration and any contrary views on compliance. We require every public utility transmission provider, including an RTO or ISO transmission provider, to file its existing or proposed OATT provisions with an explanation of how these provisions meet the requirements of this Final Rule. While many of the existing transmission planning and cost allocation processes and methods may be similar to what this Final Rule requires, others may differ because this Final Rule's requirements expand on the Order No. 890 requirements. Whether an existing process was approved previously by the Commission is not dispositive of whether that process complies with this Final Rule.

796. We recognize that it is possible that some existing RTO and ISO transmission planning and cost allocation processes may already satisfy the Commission's proposal in whole or in part. However, we decline to rule generically, in the absence of a record based on a comparison of existing practices with the provisions of this Final Rule, on the degree to which a particular RTO or ISO may already be in compliance.

797. Furthermore, public utility transmission owners that are part of Commission-jurisdictional RTOs and ISOs may demonstrate compliance through that RTO's or ISO's compliance filing and are not required to make a separate compliance filing. This includes, in response to SPP, compliance with the interregional transmission coordination requirements to the extent an RTO or ISO has negotiated the necessary arrangements on behalf of its members. In response to Omaha Public Power District, we encourage both RTO and ISO members and those not in an RTO or ISO to work together regarding regional transmission planning. We neither prohibit non-RTO/ISO members that are geographically adjacent to and/or contiguous with an RTO/ISO from participating in the RTO/ISO's regional transmission planning process nor do we require an RTO/ISO to admit nonmembers to its regional transmission planning process. The decision on whether to combine their transmission planning efforts in this way to comply with the regional transmission planning and regional cost allocation requirements and the interregional transmission coordination requirements and interregional cost allocation requirements of this Final Rule is a decision that is best left to the individual entities as

well as to the two regions in question. In addition, the OATT for the RTO or the ISO of which a public utility transmission provider is a part should include commonly agreed-to language describing that RTO/ISO's interregional transmission coordination with each neighboring transmission planning region.

798. In addition, in non-RTO/ISO regions, if public utility transmission providers in those regions decide to make combined compliance filings, they are free to do so. However, each public utility transmission providers' OATT must include the reforms required in this Final Rule.

### B. Reciprocity

#### 1. Commission Proposal

799. The Commission proposed that transmission providers that are not public utilities (i.e., non-public utility transmission providers) would have to adopt the requirements of the Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[574] The Commission

[574] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 181 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63). Under the *pro forma* OATT, a non-public utility transmission provider may satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary "safe harbor" provision of the *pro forma* OATT. A non-public utility transmission provider using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility transmission provider then must offer service under its reciprocity tariff to any public utility transmission provider

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also stated that if it finds on the appropriate record that a non-public utility transmission provider is not participating in the proposed regional transmission planning and cost allocation processes set forth in this Final Rule, the Commission may exercise its authority under FPA section 211A[575] on a case-by-case basis.[576]

**2. Comments**

800. Some commenters question whether non-jurisdictional entities can legally be required to participate in regional and interregional transmission planning and cost allocation processes. Several non-jurisdictional entities suggest that they cannot. For example, Bonneville Power asserts that the proposed mandatory cost allocation reforms could conflict with its statutory obligations. Bonneville Power states that it is required by statute to have Congressional approval before it can build facilities outside the Pacific

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whose transmission service the non-public utility transmission provider seeks to use. Second, the non-public utility transmission provider may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility transmission provider may seek a waiver of the reciprocity condition from the public utility transmission provider. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[575] FPA section 211A(b) provides, in pertinent part, that "the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential." The non-public utility transmission providers referred to in this Final Rule include unregulated transmitting utilities that are subject to FPA section 211A.

[576] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

Northwest or build major transmission facilities within the Pacific Northwest. Bonneville Power states that it is obligated to determine the appropriateness of its transmission expenditures, and those expenditures are subject to specific directives or limitations that Congress may include in its appropriation acts. As a result of these statutory obligations, Bonneville Power contends that it must retain the right to review each proposal and agree to any proposed allocation of costs from another party.

801. Western Area Power Administration states that it is a federal power marketing administration and must comply with statutory requirements that apply to such entities, such as the Anti-Deficiency Act, the Reclamation Project Act of 1939, and the Flood Control Act of 1944. Western Area Power Administration argues that these statutory requirements preclude involuntary cost allocation of third-party transmission facilities to it. Western Area Power Administration also argues that requiring it to incorporate a mandatory cost allocation share into its rates is inconsistent with the jurisdiction over, and power to review, Western Area Power Administration's rates that the Department of Energy delegated to the Commission.

802. Bonneville Power requests that the Commission explain the effect of reciprocity in the context of transmission planning and cost allocation. Bonneville Power states that if the Commission conditions reciprocity on adherence to the Proposed Rule, it requests that the Commission state in the Final Rule that it will accommodate deviations in compliance filings that are necessary to allow non-public utilities to participate.

Bonneville Power contends that if the Commission does not accept regional deviations, coordinated regional planning and cost allocation will likely be unworkable for both public and non-public utilities in the Pacific Northwest.

803. Public Power Council asserts that the Commission's proposed cost allocation method will drive non-public utilities out of the voluntary planning process. Public Power Council states that governmentally-owned utilities are subject to state statutes that may limit their ability to enter into contracts involving unknown future costs and that bind future district commissions or city councils. Public Power Council thus argues that the Commission should either abandon its proposal to require binding cost allocation agreements for non-RTO areas or withdraw its proposal that voluntary participant funding cannot be the sole method of cost allocation when the transmission provider is not a participant in an RTO. Omaha Public Power District states that it is committed to voluntary participation in the transmission planning process. However, it also states that as a state political subdivision it is not subject to the Commission's general jurisdiction under the FPA and that the Commission has no authority to set rates for it without its consent.

804. Four G&T Cooperatives argues that the Commission does not have jurisdiction under the FPA to require non-public utilities to participate in regional transmission planning processes or to agree to regional cost allocation methods. It also argues that the reciprocity provisions under Order Nos. 888 and 890 and the *pro forma* OATT do not

provide a basis for requiring non-public utilities to participate in regional transmission planning and cost allocation. National Rural Electric Coops state that the Commission has consistently refused to expand the reach of the reciprocity provision to include transmission customers other than those from which the non-public utility is taking service and those who are transmission-owning members of an RTO or ISO. G&T Cooperatives and National Rural Electric Coops request clarification that the Commission is not modifying the scope of the reciprocity requirement as established in Order Nos. 888, 890, and 890-A.

805. Western Grid Group, on the other hand, recommends that to engage non-jurisdictional utilities in regional planning groups, the Commission should make it clear that such participation is a requirement for Commission recognition of reciprocity tariffs and that all entities that share the grid have an obligation in the public interest to help plan its expansion and modernization.

806. SPP states that, consistent with the approach set forth in Order No. 890, the Commission should continue to encourage participation by non-jurisdictional entities in regional transmission planning processes. SPP also states that the Commission should consider requiring non-jurisdictional entities that have reciprocity tariffs on file with the Commission to modify those tariffs specifically to address the obligation to participate in the regional transmission planning process and cost allocation mechanism development. Similarly, San Diego Gas & Electric suggests that Order No. 888's reciprocity

requirements be enforced, as necessary. Anbaric and PowerBridge also believe that the Final Rule should apply to all transmission providers, including to those subject to the Commission's reciprocity requirements.

807. A number of commenters also address the Commission's authority under FPA section 211A. National Rural Electric Coops argue that the Commission's jurisdiction under FPA section 211A is limited to requiring a subset of unregulated transmitting utilities to provide transmission services to others on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. National Rural Electric Coops asserts that it is concerned that the Commission may be interpreting FPA section 211A to mean that it could invoke the provision in circumstances other than those in which it makes a finding that an unregulated transmitting utility is not treating its transmission customers in a way that is comparable to the way it treats itself. National Rural Electric Coops request that the Commission clarify that it will address questions of non-comparable treatment on a case-by-case basis as necessary. National Rural Electric Coops state that such a clarification could help avoid unnecessary litigation.

808. Imperial Irrigation District questions the Commission's legal authority to allocate costs to non-public utilities via either the reciprocity principle or FPA section 211A. It states that cost allocation is a rate issue, and Congress has not authorized the Commission

to set rates for non-public utilities. It argues that under the Commission's reciprocity principle, the Commission does not set rates of non-public utilities.

809. Large Public Power Council and Nebraska Public Power District state that the proposed reciprocity requirement would dramatically expand the commitment that non-public utilities were asked to make under Order No. 888 and ensuing orders and would greatly exceed the Commission's authority. They state that FPA section 211A does not permit the Commission to compel a non-public utility to contribute funding for regional or interregional transmission projects, nor would it enable the Commission to exercise any authority over the transmission planning or construction plans of a non-public utility. Sacramento Municipal Utility District urges the Commission to reconsider its proposal to invoke FPA section 211A authority on a case-by-case basis. It states that this is unnecessary, beyond the limited reciprocity requirements of Order Nos. 888 and 890, and it is beyond the Commission's authority. Western Area Power Administration states that FPA section 211A does not authorize the Commission to require unregulated transmitting utilities to engage in regional transmission planning and cost allocation.

810. Western Area Power Administration and National Rural Electric Coops request clarification that the Commission did not intend its statements in the Proposed Rule regarding FPA section 211A and the reciprocity provisions of Order Nos. 888 and 890 to expand its authority over non-public utilities. Georgia Transmission Cooperative argues that the Commission has not provided evidence to support application of FPA section

211A and that applying it would be inconsistent with prior Commission statements that non-public utilities are not subject to the same cost allocation rules as public utilities.

811. Transmission Access Policy Study Group and Colorado Independent Energy Association support the Commission's proposal to invoke reciprocity for non-jurisdictional transmission providers as needed to achieve its goals, and they agree with the Commission's decision not to invoke its authority under FPA section 211A. Colorado Independent Energy Association also recommends that to avoid the use of FPA section 211A, the Commission should provide a *pro forma* OATT and a date certain for non-jurisdictional entities to report their progress to the Commission regarding incorporation of the principles set forth in the Proposed Rule into their OATTs and practices. Transmission Agency of Northern California believes that the demonstrated willingness of non-public utility transmission providers to comply voluntarily with Commission directives shows that an explicit requirement that they comply with the Proposed Rule is unnecessary.

812. Other commenters, including MidAmerican and NextEra, suggest that the Commission should apply reciprocity or exercise its authority under FPA section 211A to require non-public utilities to participate in regional and interregional transmission planning and cost allocation processes. MidAmerican states that the Commission has the authority to require all non-jurisdictional utilities to comply with, and remain subject to, the proposed transmission planning and cost allocation requirements and that the

Commission should use this authority if it intends to achieve its stated objectives on a non-discriminatory basis. MidAmerican believes that failure to include all transmission providers will result in an inequitable burden for jurisdictional utilities and their customers, and it will create additional investment uncertainty for projects included in the regional plan. NextEra supports the use of FPA section 211A to extend the requirements of the Final Rule to unregulated transmitting utilities. It believes that invoking FPA section 211A on a case-by-case basis is risky and may not ensure maximum participation by unregulated utilities. AWEA states that the Commission should make clear its intention to invoke FPA section 211A as necessary to ensure needed participation in regional transmission efforts and cost allocation requirements.

813. Bonneville Power asserts in its response that neither the Proposed Rule, nor any of the initial comments, provide evidence that supports invoking FPA section 211A, either on a case-by-case basis or generically. Bonneville Power disagrees with MidAmerican that public utility transmission providers would be subject to undue discrimination if non-public utilities do not participate in transmission planning and cost allocation. It argues that any differences in treatment would result from adopting the Proposed Rule, not from discrimination by non-public utilities. Large Public Power Council disagrees that the Commission has authority under FPA section 211A to compel non-public utilities to participate fully in whatever planning and cost allocation rules are adopted in this

proceeding. It also states that the Commission cannot accomplish indirectly through its reciprocity provisions what it cannot accomplish directly under the statute.

814. MidAmerican also suggests that the Commission use its conditioning authority to require non-jurisdictional utilities to participate in the regional transmission planning and cost allocation processes, stating that the Commission has already taken this approach under FPA section 215. However, in reply, Large Public Power Council disagrees, noting that section 215 explicitly extends Commission jurisdiction for reliability purposes over a wide range of entities, thereby confirming that express direction from Congress is required before the Commission can exercise jurisdiction over otherwise non-jurisdictional entities.

### 3. Commission Determination

815. To maintain a safe harbor tariff, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT as it has been revised by this Final Rule. As noted in the Proposed Rule, we are encouraged, based on the efforts that followed Order No. 890, that both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which gives us authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis. However, if the Commission finds

on the appropriate record that non-public utility transmission providers are not participating in the transmission planning and transmission cost allocation process required by this Final Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

816. Given our decision above, we decline to adopt SPP's suggestion that the Commission require non-public utility transmission providers that have safe harbor tariffs on file to modify those tariffs specifically to address the transmission planning and cost allocation processes required by this Final Rule. Rather, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.[577] We also note in response to National Rural Electric Coops and others that the Commission is not proposing any changes to the reciprocity provision of the *pro forma* OATT or any other document. The Commission is not modifying the scope of the reciprocity provision.

[577] For this same reason, we find that it is not necessary to address Anbaric and PowerBridge's suggestion that this Final Rule should apply to all transmission providers, including those subject to the Commission's reciprocity provisions and enforced as necessary. However, we reiterate our determination in section IV.E.2. that an entity participating in the regional transmission planning process can be identified as the beneficiary of a regional transmission facility and allocated associated costs, irrespective of its status as a public utility under the FPA.

817. We disagree with Colorado Independent Energy Association that the Commission should impose any requirements on non-public utility transmission providers for the purpose of avoiding recourse to section 211A, as we do not see any necessity, at this time, to invoke our authority under that section. In addition, we disagree with MidAmerican, NextEra, and SPP that we should establish requirements regarding participation by non-public utility transmission providers in regional and interregional transmission planning and cost allocation processes beyond those required by reciprocity. We likewise disagree with Western Grid Group that we need to clarify for non-public utility transmission providers the importance of their participation in the processes established by this Final Rule.

818. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public and non-public utility transmission providers. In the Proposed Rule, the Commission described the significance of its proposal for non-public utility transmission providers in terms of the principle of reciprocity.[578] None of the commenters has provided a persuasive reason for departing from the position taken in the Proposed Rule. Thus, as noted above, and consistent with the approach taken in Order No. 890, the Commission expects all public utility and non-public utility transmission providers to participate in the transmission planning and cost

[578] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

allocation processes set forth in this Final Rule. The success of the reforms implemented here will be enhanced if all transmission owners participate. Further, we believe that non-public utility transmission providers will benefit greatly from the improved transmission planning and cost allocation processes required for public utility transmission providers because a well-planned grid is more reliable and provides more available, less congested paths for the transmission of electric power in interstate commerce. Those that take advantage of open access, including improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.

819. In response to G&T Cooperatives and others, we note that the Commission is not acting here under the FPA to require non-public utility transmission providers to participate in regional transmission planning processes or to agree to a method or methods for allocating the costs of their transmission facilities. Under the reciprocity provision, if a public utility transmission provider seeks transmission service from a non-public utility transmission provider to which it provides open access transmission service, the non-public utility transmission provider that owns, controls or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system.[579] A non-public utility transmission provider that elects to receive such

[579] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

service, therefore, must do so on terms that satisfy the reciprocity condition. We disagree that we are using the principle of reciprocity to expand our jurisdiction over non-public utility transmission providers. Non-public utility transmission providers are free to decide whether they will seek transmission service that is subject to the Commission's jurisdiction, and we do not exercise jurisdiction over them when we determine the terms under which public utility transmission providers must provide that transmission service.

820. While a number of commenters argue that this Final Rule's reforms could conflict with their statutory obligations, no specific conflict has been presented for us to act on in this Final Rule. Concerns about possible conflicts should be raised in transmission cost allocation discussions and any subsequent Commission proceedings on proposed transmission cost allocation methods.

821. We disagree with National Rural Electric Coops that our discussion of FPA section 211A in the Proposed Rule is unclear or ambiguous. However, in response to National Rural Electric Coops we note that our intent is to invoke section 211A only on a case-by-case basis. We see no reason to reconsider our position on section 211A as Sacramento Municipal Utility District requests, nor a need to address additional arguments concerning the scope of our authority under section 211A given that we are not acting under section 211A in issuing this Final Rule. Likewise, in response to Georgia Transmission Cooperative, we do not need to provide evidence in this

proceeding to support the application of FPA section 211A because we are not applying it here.

822. With regard to Transmission Agency of Northern California's suggestion that an explicit requirement that non-public utility transmission providers comply with the Proposed Rule is unnecessary because they are already complying, we note that this Final Rule does not include any such explicit requirement and instead only notes an expectation that non-public utility transmission providers will participate voluntarily.

## VI. Information Collection Statement

823. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[580] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

824. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[581] In the Proposed Rule, the Commission solicited

[580] 5 C.F.R. 1320.11(b).

[581] 44 U.S.C. 3507(d).

comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission also included a chart that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements. The Commission received one comment from Arizona Public Service Company specifically addressing the Commission burden estimate in the Proposed Rule.

825. Arizona Public Service Company states that while it supports the need for a robust regional transmission planning process, it contends that the burden estimate in the Proposed Rule understated the number of hours and the average rates of the employees working on these processes. As an example, Arizona Public Service Company states that it participates in WestConnect, which in the past twelve months has involved over two dozen regional or subregional transmission planning meetings. According to Arizona Public Service Company, many of these meetings last an entire day, and require a significant amount of preparation work prior to the meeting. It further contends that the Commission should have included calculation of travel expenses of participants in the regional transmission planning processes, including transportation, lodging, and meal expenses.

826. In the Proposed Rule, the Commission estimated the number of hours required for the average public utility transmission provider to comply with the minimum requirements included in the Proposed Rule. The burden estimates in this Final Rule represent the incremental burden changes related only to the requirements set forth in this Final Rule.[582] It should also be noted that the burden estimates are averages for all of the filers. Furthermore, we acknowledge that some regional transmission planning processes have been developed to date that may require more time to participate than the estimate that the Commission provided in the Proposed Rule. However, the fact that such processes have been developed reflects the choice of the participants in those regional transmission planning processes on how to comply with the Commission's rules, it does not mean that the Commission's rules necessarily required such processes. For example, we note that public utility transmission providers may decide, in a particular region or between regions, to develop a regional transmission planning process that includes more objectives and procedures than the minimum set forth in this Final Rule, which may increase the number of hours necessary to participate. In any event, Arizona Public Service Company did not provide any estimates of the number of hours that it has taken to participate in its regional transmission planning processes, nor suggested alternative

[582] 5 C.F.R. 1320.3(b)(1)-(2).

estimates. Thus, for the most part, the Commission adopts the burden estimates that it set out in the Proposed Rule.

827. As for the hourly rates of the employees, the Commission relies on average national salaries to develop hourly rates of the employees necessary to comply with the requirements adopted in this Final Rule. Again, we note that this is an average rate, and that rates may be higher or lower depending on the area of the country where the public utility transmission provider is located. Therefore, we find that the averages in the Proposed Rule are reasonable estimates of the average national rates for the employees described below.

828. Finally, the Commission has included, in its burden estimate, the number of hours that a public utility transmission provider may need to travel to participate in a regional transmission planning process and interregional transmission coordination procedures.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in this Final Rule follow.

| **FERC-917 - Proposed Reporting Requirements in RM10-23** | **Annual Number of Respondents (Filers)** | **Annual Number of Responses** | **Hours per Response** | **Total Annual Hours in Year 1** | **Total Annual Hours in Subsequent Years** |
|---|---|---|---|---|---|
| Participation in a transparent and open regional transmission planning process that meets regional transmission planning principles, includes consideration of transmission needs driven by Public | 132 | 132 | 110 hrs in Year 1; 52 hrs in subsequent years | 14520 | 6864 |

| | | | | | |
|---|---|---|---|---|---|
| Policy Requirements, identifies and evaluates transmission facilities to meet needs, develops cost allocation method(s), and produces a regional transmission plan that describes and incorporates a cost allocation method(s) that meets the Commission's principles. | | | | | |
| Development of interregional transmission coordination procedures that meet the Commission's requirements, including the ongoing requirement to provide or post certain transmission planning information and provide annual data exchange, as well as the development of a cost allocation method for interregional transmission facilities that meets the Commission's principles. | 132 | 132 | 133 hrs in Year 1; 43 hrs in subsequent years | 17556 | 5676 |
| Conforming tariff changes for local transmission planning, including those related to consideration of transmission needs driven by Public Policy Requirements; and conforming tariff changes for regional transmission planning and interregional transmission coordination. | 132 | 132 | 57 hrs in Year 1; 25 hrs in subsequent years | 7524 | 3300 |
| **Total Estimated Additional Burden Hours, Proposed for FERC-917 in NOPR in RM10-23** | | | | 39600 | 15840 |

Cost to Comply:

Year 1: $4,514,400 or [39,600 hours X $114 per hour[583]]

Subsequent Years: $1,805,760 or [15,840 hours X $114 per hour]

Title: FERC-917

Action: Proposed Collections.

OMB Control No: 1902-0233.

Respondents: Public Utility Transmission Providers. An RTO or ISO also may file some materials on behalf of its members.

Frequency of Responses: Initial filing and subsequent filings.

Necessity of the Information:

829. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission adopts these amendments to the *pro forma* OATT to correct certain deficiencies in the transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this Final Rule is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. We expect to achieve this goal through this Final Rule by reforming electric transmission

[583] The estimated cost of $114 an hour is the average of the hourly costs of: attorney ($200), consultant ($150), technical ($80), and administrative support ($25).

planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

830. Interested persons may obtain information on reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should include OMB Control No. 1902-0233 and Docket No. RM10-23-000.

## VII. Environmental Analysis

831. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[584] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule

[584] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

because section 380.4(a)(15) of the Commission's regulations provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[585] The reforms herein do not require transmission or other facilities to be built, but rather establish transmission planning mechanisms that will result in a more appropriate allocation of costs and thus better ensure just and reasonable and not unduly discriminatory or preferential rates.

## VIII. Regulatory Flexibility Act Analysis

832. The Regulatory Flexibility Act of 1980 (RFA)[586] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890. The total number of public utility transmission providers that, absent waiver, must modify their current OATTs by filing the revised *pro forma* OATT is 132. Of these public utility transmission providers,

[585] 18 C.F.R. 380.4(a)(15).

[586] 5 U.S.C. 601-612.

only 9 filers, or 6.8 percent, have output of four million MWh or less per year.[587] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to request waiver of these requirements. The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

## IX. Document Availability

833. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

834. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

[587] A firm is "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt-hours. Based on the filers of the annual FERC Form 1 and Form 1-F, as well as the number of companies that have obtained waivers, we estimate that 6.8 percent of the filers are "small."

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

835. User assistance is available for eLibrary and the Commission's web site during normal business hours from FERC Online Support at (202)502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

## X. Effective Date and Congressional Notification

836. These regulations are effective [insert date 60 days after publication in the **FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit this Final Rule to both houses of Congress and the Government Accountability Office.

List of subjects in 18 CFR Part 35

Electric power rates
Electric utilities
Reporting and recordkeeping requirements

By the Commission. Commissioner Moeller is dissenting, in part, with a separate statement attached.

( S E A L )

Nathaniel J. Davis, Sr.,
Deputy Secretary.

## Regulatory Text

In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

**PART 35—FILING OF RATE SCHEDULES AND TARIFFS**

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 71-7352.

2. Amend § 35.28 as follows:

a. Paragraph (c)(1) through (c)(1)(iii) are revised.

b. Paragraph (c)(1)(vi) is revised.

c. Paragraphs (c)(3), (c)(3)(i), and (c)(3)(ii) are revised.

d. Paragraphs (c)(4) through (c)(4)(ii) are revised.

e. Paragraph (d) (1) is revised.

f. Paragraph (e)(1) is revised.

**§ 35.28 Non-discriminatory open access transmission tariff.**

* * * * *

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access

and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms) and further revised in Order No. 1000, FERC Stats. & Regs. ¶ _____ (Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306, Order No. 890, FERC Stats. & Regs. ¶ 32,241, and Order No. 1000, FERC Stats. & Regs. ¶ _____.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ _____, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the **FEDERAL REGISTER**], it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, as amended by Order No. 1000, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in

accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ ____.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the **FEDERAL REGISTER**], such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

* * * * *

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs. ¶ _____, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ _____.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the

transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ _____, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ _____.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after [insert date that is 60 days after date of publication of the Final Rule in the **FEDERAL REGISTER**], this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before [insert date that is 60 days after date of publication of the Final Rule in the **FEDERAL REGISTER**], a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns,

controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff consistent with Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ ____.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ _____, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ _____ .

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ ____,

pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ ____.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ _____, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Order No. 1000, FERC Stats. & Regs ¶ ____.

(d) Waivers. * * *

(1) No later than [insert date that is 60 days after date of publication of the Final Rule in the **FEDERAL REGISTER**], or

* * * * *

(e) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ _____ .

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

**Appendix A: Summary of Compliance Filing Requirements**

| Deadline (months after the effective date of the Final Rule) | Compliance Action | Section of the Final Rule |
|---|---|---|
| 12 months | Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include local and regional transmission planning processes that are consistent with the requirements of this Final Rule. | Section III.A. |
| 12 months | Submit revised Attachment K of the *pro forma* OATT and other Commission jurisdictional documents to include a cost allocation method or methods for regional cost allocation consistent with principles of this Final Rule. | Section III.C. |
| 18 months | Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include an interregional transmission coordination procedure or procedures consistent with the requirements of this Final Rule. | Section IV.C. |
| 18 months | Submit revised Attachment K of the *pro* | Section IV.D. |

*forma* OATT and any other Commission jurisdictional documents to include a cost allocation method or methods for interregional cost allocation consistent with the principles of this Final Rule.

## Appendix B: Abbreviated Names of Commenters

The following two tables contain the abbreviated names of initial and reply commenters that are used in this Final Rule.

### Initial Commenters

| Abbreviation | Initial Commenter(s) |
|---|---|
| 26 Public Interest Organizations | Alliance for Clean Energy New York; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Earthjustice; Environment Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; National Audubon Society; Natural Resources Defense Council; Pennsylvania Land Trust Alliance; Nevada Wilderness Project; NW Energy Coalition; Pace Energy and Climate Center; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; and Western Grid Group |
| Ad Hoc Coalition of Southeastern Utilities | Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company) |
| AEP | American Electric Power Service Corporation |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Alabama PSC | Alabama Public Service Commission |
| Allegheny Energy Companies | Monongahela Power Company; The Potomac Edison Company; West Penn Power Company; Trans-Allegheny Interstate Line Company; and Allegheny Energy Supply Company, LLC |
| ALLETE | ALLETE, Inc. |
| Alliant Energy | Alliant Energy Corporate Services, Inc. |
| American Antitrust Institute | American Antitrust Institute |
| American Forest & Paper | American Forest & Paper Association |
| American Transmission | American Transmission Company LLC |
| Anbaric and PowerBridge | Anbaric Holding, LLC; PowerBridge, LLC |
| APPA | American Public Power Assocation |
| Arizona Corporation Commission | Arizona Corporation Commission |
| Arizona Public Service Company | Arizona Public Service Company |
| Atlantic Grid | Atlantic Grid Development, LLC on behalf of Atlantic Wind Connection |
| Avista and Puget Sound | Avista Corporation and Puget Sound Energy, Inc. |
| AWEA | American Wind Energy Association; Wind on the Wires; Renewable Northwest Project; Mid-Atlantic Renewable Energy Coalition; Alliance for Clean Energy, Inc.; Interwest Energy Alliance; RENEW; the Wind Coalition; and Center for Energy Efficiency and Renewable Technologies |
| Baltimore Gas & Electric | Baltimore Gas & Electric Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Bay Area Municipal Transmission Group | City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California |
| Bonneville Power | Bonneville Power Administration |
| Boundless Energy and Sea Breeze | Boundless Energy, LLC and Sea Breeze Pacific Regional Transmission System |
| Brattle Group (The) | Peter Fox-Penner; Johannes Pfeifenberger; and Delphine Hou |
| California Commissions | California Public Utilities Commission and the Energy Resources Conservation and Development Commission of the State of California |
| California ISO | California Independent System Operator Corporation |
| California Municipal Utilities | California Municipal Utilities Association (Cities of Alameda; Anaheim; Azusa; Banning; Burbank; Cerritos; Colton; Corona; Glendale; Gridley; Healdsburg; Hercules; Lodi; Lompoc; Moreno Valley; Needles; Palo Alto; Pasadena; Pittsburg; Rancho Cucamonga; Redding; Riverside; Roseville; Santa Clara; Shasta Lake; Ukiah; and Vernon; the Imperial; Merced; Modesto; Turlock Irrigation Districts; the Northern California Power Agency; Southern California Public Power Authority; Transmission Agency of Northern California; Lassen Municipal Utility District; Power and Water Resources Pooling Authority; Sacramento Municipal Utility District; the Trinity and Truckee Donner Public Utility Districts; the Metropolitan Water District of Southern California; and the City and County of San Francisco, and Hetch-Hetchy) |
| California Transmission | Sacramento Municipal Utility District; the Imperial |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Planning Group | Irrigation District; the Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company and the San Diego Gas & Electric Company |
| California State Water Project | California Department of Water Resources State Water Project |
| CapX2020 Utilities | Central Minnesota Municipal Power Agency; Dairyland Power Cooperative; Great River Energy; Minnesota Power; Minnkota Power Cooperative; Missouri River Energy Services; Otter Tail Power Company; Rochester Public Utilities; Southern Minnesota Municipal Power Agency; WPPI Energy; and Xcel Energy Inc. |
| Champlain Hudson | Champlain Hudson Power Express, Inc. |
| City and County of San Francisco | City and County of San Francisco |
| City of Los Angeles Department of Water and Power | City of Los Angeles Department of Water and Power |
| City of Santa Clara | City of Santa Clara, California |
| Clean Energy Group | Clean Energy Group |
| Clean Line | Clean Line Energy Partners LLC |
| Coalition for Fair Transmission Policy | CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Colorado Independent Energy Association | Colorado Independent Energy Association |
| ColumbiaGrid | ColumbiaGrid (Avista Corporation; Bonneville Power Administration; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 1 of Snohomish County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; City of Tacoma, Department of Public Utilities, Light Division; and the City of Seattle, by and through its City Light Department) |
| Connecticut & Rhode Island Commissions | Connecticut Department of Public Utility Control and the Rhode Island Public Utilities Commission |
| Conservation Law Foundation | Conservation Law Foundation |
| Consolidated Edison and Orange & Rockland | Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. |
| Consumers Energy Company | Consumers Energy Company |
| Dayton Power and Light | Dayton Power and Light Company (The) |
| DC Energy | DC Energy, LLC |
| Delaware PSC | Delaware Public Service Commission |
| Direct Energy | Direct Energy Services, LLC; Direct Energy Business, LLC; and Energy America, LLC |
| Dominion | Dominion Resources Services, Inc. |
| Duke | Duke Energy Corporation |
| Duquesne Light Company | Duquesne Light Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| EARTHJUSTICE | EARTHJUSTICE |
| East Texas Cooperatives | East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative |
| Eastern Massachusetts Consumer-Owned System | Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Hingham Municipal Lighting Plant; Reading Municipal Light Department; Taunton Municipal Lighting Plant; and Wellesley Municipal Light Plant |
| Edison Electric Institute | Edison Electric Institute |
| EIF Management | EIF Management, LLC |
| Electricity Consumers Resource Council and the Associated Industrial Groups | Electricity Consumers Resource Council; American Chemistry Council; Association of Businesses Advocating Tariff Equity; Carolina Utility Customers Association; Coalition of Midwest Transmission Customers; Florida Industrial Power Users Group; Georgia Industrial Group-Electric; Industrial Energy Users – Ohio; Oklahoma Industrial Energy Consumers; PJM Industrial Customer Coalition; West Virginia Energy Users Group; and Wisconsin Industrial Energy Group |
| Enbridge | Enbridge Inc. |
| Energy Consulting Group | Energy Consulting Group LLC (representing Central Georgia EMC; Cobb EMC; Diverse Power Incorporated; Pataula EMC; Snapping Shoals EMC; Upson EMC; and Washington EMC) |
| Energy Future Coalition Group | Energy Future Coalition; Alliance for Clean Energy New York, Inc.; American Wind Energy Association; BrightSource Energy, Center for American Progress, Conservation Law Foundation; |

| Abbreviation | Initial Commenter(s) |
|---|---|
| | Environmental Northeast; Fresh Energy; Interwest Energy Alliance; Invenergy Thermal Development, LLC; Invenergy Wind Development, LLC; ITC Holdings, Corp.; Mesa Power Group; Mid-Atlantic Renewable Energy Coalition; Natural Resources Defense Council; Renewable Northwest Project; Sierra Club; Solar Energy Industries Association; The FERC Project; The Stella Group, Ltd.; The Wilderness Society; Union of Concerned Scientists; Utility Workers Union of America; and Western Grid Group |
| Environmental Defense Fund | Environmental Defense Fund |
| Environmental NGOs | Environmental Non-Governmental Organizations (Environmental Integrity Project; Izaak Walton League of America; Clean Air Council; Michigan Environmental Council; Ohio Citizen Action; Natural Resources Defense Council; Fresh Energy; Citizens for Pennsylvania's Future; Sierra Club; and Earthjustice) |
| E.ON | E.ON U.S. LLC |
| E.ON Climate & Renewables North America | E.ON Climate & Renewables North America, LLC |
| Exelon | Exelon Corporation |
| Federal Trade Commission | Federal Trade Commission |
| First Wind | First Wind Energy, L.L.C. |
| FirstEnergy Service Company | FirstEnergy Service Company, on behalf of FirstEnergy Companies: Ohio Edison Company; Pennsylvania Power Company; The Cleveland Electric Illuminating Company; The Toledo Edison Company; American Transmission Systems, Incorporated; Jersey Central Power & Light |

| Abbreviation | Initial Commenter(s) |
|---|---|
| | Company; Metropolitan Edison Company; and Pennsylvania Electric Company, and FirstEnergy Solutions Corp. and their respective electric utility subsidiaries and affiliates |
| Florida PSC | Florida Public Service Commission |
| Four G&T Cooperatives | Associated Electric Cooperative; Basin Electric Power Cooperative; and Tri-State Generation and Transmission Association |
| Gaelectric North America | Gaelectric North America |
| Georgia Transmission Corporation | Georgia Transmission Corporation |
| Governors of Delaware and Maryland | Governors of Delaware and Maryland |
| Grasslands | Grasslands Renewable Energy LLC |
| Green Energy and 21st Century | Green Energy Express LLC and 21st Century Transmission Holdings, LLC |
| Grid Solar | Grid Solar, LLC |
| Horizon Wind Energy | Horizon Wind Energy LLC |
| Iberdrola Renewables | Iberdrola Renewables, Inc. |
| Ignacio Perez-Arriaga | Ignacio J. Perez-Arriaga |
| Illinios Commerce Commission | Illinois Commerce Commission |
| Imperial Irrigation District | Imperial Irrigation District |
| Independent Energy Producers Association | Independent Energy Producers Association |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Indianapolis Power & Light | Indianapolis Power & Light Company |
| Indicated PJM Transmission Owners | Monongahela Power Company; The Potomac Edison Company and West Penn Power Company; and Trans-Allegheny Interstate Line Company; Baltimore Gas and Electric Company; The Dayton Power and Light Company; Duquesne Light Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; Pennsylvania Electric Company; Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; Atlantic City Electric Company; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC; UGI Utilities, Inc.; and Virginia Electric and Power Company |
| Integrated Transmission Benefits Model Proponents | Maine PUC; Maine Office of the Public Advocate; Maine Office of Energy Independence and Security; New Hampshire Public Utilities Commission; Environment Northeast; and Conservation Law Foundation |
| Integrys | Wisconsin Public Service Corporation; Upper Peninsula Power Company; and Integrys Energy Services, Inc. |
| Invenergy | Invenergy Wind Development LLC |
| ISO New England | ISO New England Inc. |
| ISO/RTO Council | California Independent System Operator; ISO New |

| Abbreviation | Initial Commenter(s) |
|---|---|
| | England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc. |
| ITC Companies | International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP |
| Joint Commenters | American Chemistry Council; American Forest & Paper Association; American Public Power Association; California Municipal Utilities Association; California Public Utilities Commission; Electricity Consumers Resource Council; Indiana Utility Regulatory Commission; Modesto Irrigation District; Montana Public Service Commission; National Association of State Utility Consumer Advocates; New England Conference of Public Utility Commissioners; New Hampshire Office of Consumer Advocate; New Jersey Division of Rate Counsel; New York State Public Service Commission; Office of the Nevada Attorney General, Bureau of Consumer Protection; Old Dominion Electric Cooperative; Sacramento Municipal Utility District; South Dakota Public Utilities Commission; State of Maine, Office of the Public Advocate; Transmission Agency of Northern California; Utility Reform Network; Vermont Department of Public Service; and Vermont Public Service Board |
| Kansas City Power & Light and KCP&L Greater Missouri | Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company |
| Kansas Corporation Commission | Kansas Corporation Commission |
| Land Trust Alliance | Land Trust Alliance |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Large Public Power Council | Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Power and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities |
| Long Island Power Authority | Long Island Power Authority |
| LS Power | LS Power Transmission, LLC |
| Maine PUC | Maine Public Utility Commission |
| Maine Utilities | Bangor Hydro Electric Company; Central Maine Power Company; and Maine Public Service |
| Massachusetts Departments | Massachusetts Department of Public Utilities and Massachusetts Department of Energy Resources |
| Massachusetts Municipal and New Hampshire Electric | Massachusetts Municipal Wholesale Electric Company and New Hampshire Electric Cooperative, Inc. |
| Michigan Citizens Against Rate Excess | Michigan Citizens Against Rate Excess |
| MidAmerican | MidAmerican Energy Holdings Company |
| MISO | Midwest Independent System Transmission Operator, Inc. |

| Abbreviation | Initial Commenter(s) |
|---|---|
| MISO Transmission Owners | Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc. |
| Minnesota PUC and Minnesota Office of Energy Security | Minnesota Public Utilities Commission and Minnesota Office of Energy Security |
| Modesto Irrigation District | Modesto Irrigation District |
| Multiparty Commenters | American Electric Power Corp.; AWEA, Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; and SEIA |
| NARUC | National Association of Regulatory Utility Commissioners |
| National Audubon Society | National Audubon Society |
| National Grid | National Grid USA |

| Abbreviation | Initial Commenter(s) |
|---|---|
| National Rural Electric Coops | National Rural Electric Cooperative Association |
| Natural Resources Defense Council | Natural Resources Defense Council |
| Nebraska Public Power District | Nebraska Public Power District |
| NEPOOL | New England Power Pool Participants Committee |
| Nevada Hydro | Nevada Hydro Company |
| New England States Committee on Electricity | New England States Committee on Electricity |
| New England Transmission Owners | Bangor Hydro Electric Company; Central Maine Power Company; NSTAR Electric Company; New England Power Company; Northeast Utilities Service Company on behalf of the Northeast utilities system operating companies; The United Illuminating Company; and Vermont Electric Transmission Company, Inc., on behalf of itself and its affiliate, Vermont Transco LLC |
| New Jersey Board | New Jersey Board of Public Utilities |
| New Jersey Division of Rate Counsel | New Jersey Division of Rate Counsel |
| New York ISO | New York Independent System Operator, Inc. |
| New York PSC | New York State Public Service Commission |
| New York Transmission Owners | Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and |

| Abbreviation | Initial Commenter(s) |
|---|---|
| | Electric Corporation |
| NextEra | NextEra Energy, Inc. |
| North Carolina Agencies | North Carolina Utilities Commission and Public Staff of the North Carolina Utilities Commission |
| Northeast Utilities | Northeast Utilities Service Company |
| Northern California Power Agency | Northern California Power Agency |
| Northern Tier Transmission Group | Northern Tier Transmission Group |
| Northwest & Intermountain Power Producers Coalition | Calpine Corporation; Capital Power Operations; Constellation Energy Control & Dispatch; EverPower Renewables; Exergy Development Group; First Wind; Horizon Wind Energy; Invenergy; LS Power Associates; Ridgeline Energy; Shell Energy North America; TransAlta Marketing, Inc; and TransCanada |
| NorthWestern Corporation (Montana) | NorthWestern Corporation (Montana) |
| NRG Companies | NRG Companies |
| NV Energy | Nevada Power Company and Sierra Pacific Power Company |
| Ohio Consumers' Counsel and West Virginia Consumer Advocate Division | Ohio Consumers' Counsel and West Virginia Consumer Advocate Division |
| Oklahoma Corporation Commission | Oklahoma Corporation Commission |
| Oklahoma Gas and Electric | Oklahoma Gas and Electric Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Company | |
| Old Dominion | Old Dominion Electric Cooperative |
| Omaha Public Power District | Omaha Public Power District |
| Organization of MISO States | Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission |
| Pacific Gas and Electric<br>Pattern Transmission | Pacific Gas and Electric Company<br>Pattern Transmission LP |
| Pennsylvania PUC | Pennsylvania Public Utility Commission |
| PHI Companies | Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; and Atlantic City Electric Company |
| Pioneer Transmission | Pioneer Transmission, LLC |
| PJM | PJM Interconnection, L.L.C. |
| Powerex | Powerex Corp. |
| PPL Companies | PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; and PPL Colstrip II, LLC |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Primary Power | Primary Power, LLC |
| PSC of Wisconsin | Public Service Commission of Wisconsin |
| PSEG Companies | Public Service Electric and Gas Company; PSEG Power LLC; and PSEG Energy Resources & Trade LLC |
| Public Power Council | Public Power Council |
| PUC of Nevada | Public Utility Commission of Nevada |
| PUC of Ohio | Public Utility Commission of Ohio |
| Sacramento Municipal Utility District | Sacramento Municipal Utility District |
| Salt River Project | Salt River Project Agricultural Improvement and Power District |
| San Diego Gas & Electric | San Diego Gas & Electric Company |
| Six Cities | Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, CA |
| Solar Energy Industries and Large-scale Solar | Solar Energy Industries Association and Large-scale Solar Association |
| Sonoran Institute | Sonoran Institute |
| South Carolina Electric & Gas | South Carolina Electric & Gas Company |
| Southern California Edison | Southern California Edison Company |
| Southern Companies | Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| Southwest Area Transmission Subregional Planning Group | Southwest Area Transmission Subregional Planning Group |
| SPP | Southwest Power Pool, Inc. |
| Starwood | Starwood Energy Group Global, L.L.C. |
| Sunflower and Mid-Kansas | Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC |
| Transmission Access Policy Study Group | Transmission Access Policy Study Group |
| Transmission Agency of Northern California | Transmission Agency of Northern California |
| Transmission Dependent Utility Systems | Arkansas Electric Cooperative Corporation; Golden Spread Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc. |
| Tucson Electric | Tucson Electric Power Company |
| U.S. Senators Dorgan and Reid | United States Senators Byron Dorgan and Harry Reid |
| Vermont Electric | Vermont Electric Power Company, Inc. |
| Virginia State Corporation Commission | Virginia State Corporation Commission |
| Washington Utilities and Transportation Commission | Washington Utilities and Transportation Commission |
| WECC | Western Electricity Coordinating Council |
| Westar | Westar Energy, Inc. and Kansas Gas and Electric Company |

| Abbreviation | Initial Commenter(s) |
|---|---|
| WestConnect Planning Parties | Arizona Public Service Company; Basin Electric Power Cooperative; Black Hills Corporation; El Paso Electric Company; Imperial Irrigation District; NV Energy; Public Service Company of New Mexico; Sacramento Municipal Utility District; Salt River Project Agricultural Improvement and Power District; Southwest Transmission Cooperative, Inc.; Transmission Agency of Northern California; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company; and Western Area Power Administration |
| Western Area Power Administration | Western Area Power Administration |
| Western Grid Group | Western Grid Group |
| Western Independent Transmission Group | Western Independent Transmission Group |
| The Wilderness Society and Western Resource Advocates | The Wilderness Society and Western Resource Advocates |
| Wind Coalition (The) | Wind Coalition (The) |
| WIRES | Working Group for Investment in Reliable and Economic Electric Systems |
| Wisconsin Electric Power Company | Wisconsin Electric Power Company |
| Xcel | Xcel Energy Services Inc. |

**Reply Commenters**

| Abbreviation | Reply Commenter(s) |
|---|---|

| Abbreviation | Reply Commenter(s) |
|---|---|
| 26 Public Interest Organizations | Citizens Utility Board of Wisconsin; Climate and Energy Project; CNT Energy; Conservation Law Foundation; Earth Justice; Energy Conservation Council of Pennsylvania; Energy Future Coalition; Environmental Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; Midwest Energy Efficiency Alliance; National Audubon Society; Natural Resources Defense Council; Northeast Energy Efficiency Partnerships; NW Energy Coalition; Pace Energy and Climate Center; Pennsylvania Land Trust Association; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; Western Grid Group; Western Resource Advocates; Wind on the Wires*[1] |
| Ad Hoc Coalition of Southeastern Utilities | Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; Louisville Gas & Electric Company and Kentucky Utilities Company; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power |

[1] A "*" indicates that the composition of this group as altered in the reply comment filing.

| Abbreviation | Reply Commenter(s) |
|---|---|
| | Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company)* |
| AEP | American Electric Power Service Corporation |
| Alabama Municipal Electric Authority | Alabama Municipal Electric Authority |
| APPA | American Public Power Association |
| Arizona Public Service Company | Arizona Public Service Company |
| Atlantic Grid | Atlantic Grid Development, LLC, on behalf of Atlantic Wind Connection |
| Baltimore Gas & Electric | Baltimore Gas and Electric Company |
| Bay Area Municipal Transmission Group | City of Santa Clara, California; the City of Palo Alto, California; the City of Alameda, California |
| Bonneville Power | Bonneville Power Administration |
| California ISO | California Independent System Operator Corporation |
| California PUC | California Public Utilities Commission |
| California Transmission Planning Group | Sacramento Municipal Utility District; the Imperial Irrigation District; the City of Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company; San Diego Gas & Electric Company |

| Abbreviation | Reply Commenter(s) |
|---|---|
| City of Santa Clara | City of Santa Clara, California |
| Coalition for Fair Transmission Policy | CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company |
| Commissioner Nathan A. Skop of the Florida PSC | Commissioner Nathan A. Skop of the Florida PSC |
| Conservation Law Foundation | Conservation Law Foundation |
| Consolidated Edison and Orange & Rockland | Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. |
| EarthJustice and Environmental Groups | EARTHJUSTICE; Environmental Integrity Project; Natural Resources Defense Council; Environmental Law & Policy Center; Fresh Energy |
| EarthJustice et al. | EARTHJUSTICE on behalf of Sierra Club; Natural Resources Defense Council; National Rural Electric Coops; Citizens for Pennsylvania's Future |
| Eastern Environmental and Conservation Groups | New Jersey Highlands Coalition; New Jersey Chapter of the Sierra Club; Delaware Riverkeeper Network; New Jersey Conservation Foundation; Stop the Lines |
| East Texas Cooperatives | East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative |
| Edison Electric Institute | Edison Electric Institute |

| Abbreviation | Reply Commenter(s) |
|---|---|
| EIF Management | EIF Management, LLC |
| Entergy | Entergy Services Inc., on behalf of the Entergy Operating Companies (Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. |
| Environmental Defense Fund | Environmental Defense Fund |
| Exelon | Exelon Corporation |
| First Wind | First Wind Energy, L.L.C. |
| Florida PSC | Florida Public Service Commission |
| Green Energy and 21st Century | Green Energy Express LLC and 21st Century Transmission Holdings, LLC |
| H-P Energy Resources | H-P Energy Resources LLC |
| Identified New England Transmission Owners | Identified New England Transmission Owners |
| Illinois Commerce Commission | Illinois Commerce Commission |
| ISO New England | ISO New England Inc. |
| ISO/RTO Council | California Independent System Operator; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc. |
| ITC Companies | International Transmission Company; Michigan Electric Transmission Company, |

| Abbreviation | Reply Commenter(s) |
|---|---|
| | LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP |
| Large Public Power Council | Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; Tacoma Public Utilities |
| LS Power | LS Power Transmission, LLC |
| Maine Parties | Maine Public Utilities Commission; Maine Office of the Public Advocate; Maine Governor's Office of Energy, Independence and Security |
| MEAG Power | MEAG Power |
| MISO Transmission Owners | Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota |

| Abbreviation | Reply Commenter(s) |
|---|---|
| | Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc. |
| Multiparty Commenters | American Electric Power Corp.; AWEA; Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; SEIA; and Western Grid Group* |
| National Grid | National Grid USA |
| National Rural Electric Coops | National Rural Electric Cooperative Association |
| New England States Committee on Electricity | New England States Committee on Electricity |
| New Jersey Board | New Jersey Board of Public Utilities |
| New York Transmission Owners | Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation |
| NextEra | NextEra Energy, Inc. |

| Abbreviation | Reply Commenter(s) |
|---|---|
| North Dakota and South Dakota Commission | North Dakota Public Service Commission and South Dakota Public Utilities Commission |
| Ohio Consumers' Counsel | Office of the Ohio Consumers' Counsel |
| Old Dominion | Old Dominion Electric Cooperative |
| Organization of MISO States | Illinois Commerce Commission; Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; Public Utilities Commission of Ohio; Pennsylvania Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission* |
| Pacific Gas and Electric | Pacific Gas and Electric Company |
| Pattern Transmission | Pattern Transmission LP |
| PJM | PJM Interconnection, L.L.C. |
| Powerex | Powerex Corp. |
| PPL Companies | PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; PPL Maine, LLC; PPL Wallingford Energy LLC* |

| Abbreviation | Reply Commenter(s) |
|---|---|
| PSEG Companies | Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC |
| Sacramento Municipal Utility District | Sacramento Municipal Utility District |
| San Diego Gas & Electric | San Diego Gas & Electric Company |
| Sierra Club | 8,203 Sierra Club members, supporters, and electric system ratepayers |
| Solar Energy Industries and Large-scale Solar | Solar Energy Industries Association and Large-scale Solar Association |
| South Carolina Office of Regulatory Staff | South Carolina Office of Regulatory Staff |
| Southern California Edison | Southern California Edison Company |
| Southern Companies | Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company |
| Southern New England States | Southern New England States |
| Transmission Agency of Northern California | Transmission Agency of Northern California |
| Western Independent Transmission Group | Western Independent Transmission Group |
| WIRES | Working Group for Investment in Reliable and Economic Electric Systems |

## Appendix C: *Pro Forma* Open Access Transmission Tariff

### *Pro Forma* OATT

### ATTACHMENT K

### Transmission Planning Process

### Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning

process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

**Regional Transmission Planning**

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of

transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional transmission planning process must include sufficient

detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission plan;

(v) The obligations of and methods for transmission customers to submit data;

(vi) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(vii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(viii) The dispute resolution process;

(ix) The study procedures for economic upgrades to address congestion or the integration of new resources;

(x) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or

methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

**Interregional Transmission Coordination**

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;
(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;
(3) An agreement to exchange, at least annually, planning data and information;
and (4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities — Docket No. RM10-23-000

(Issued July 21, 2011)

MOELLER, Commissioner, *dissenting in part*:

While I offer substantial praise for this final rule, the Commission should have taken a different approach to several important issues. But before addressing these issues, we must recognize that all of the nation's difficulties in building needed transmission will not be resolved by this rule. Rather, this rule largely addresses planning for long-distance transmission lines, which is only a subset of the critical issues that are inhibiting needed investment.

This rule cannot address issues like the delays caused by other federal agencies in the siting of important projects, as this Commission lacks the legal authority to require other federal agencies to act.[1] And this rule also cannot address issues of state law, regardless of the reliability needs that are served by a new transmission line. Moreover, and as described further below, this rule did not address whether a transmission provider can thwart competitive options by refusing to upgrade its transmission system. For these reasons, this rule will not resolve all of the difficult issues that discourage this nation from constructing needed transmission lines.

Regarding the issues that the final rule does address, I believe that the owner of a transmission network should have been provided with greater flexibility to ensure the reliability of its own network. Moreover, the rule should have clarified that a right of first refusal is not a right of "forever" refusal. That is, a right to "forever" block a needed transmission project could prevent the lowest-cost power from reaching consumers.

[1] See the comments of PJM at 17, which state that, "[t]he PJM Board approved the Susquehanna-Roseland 500 kV line in 2007. The Susquehanna-Roseland line was approved by the state regulatory commissions in Pennsylvania and New Jersey for 2012. The line is currently delayed by the National Parks Service [sic] and is not expected to be in service until 2014 at the earliest."

To encourage needed transmission investment, the final rule permits incumbent transmission owners to maintain their existing rights of first refusal for: (1) local projects where the incumbent does not seek to share the costs of those projects; (2) upgrades to existing assets; and (3) projects on existing right of way.[2] However, notably absent from these categories of projects is the right of a utility to build a project within its franchised service territory in order to maintain the reliability of its existing network – regardless of whether the cost of that project is allocated on a regional basis.

In my view, transmission providers should have been entitled under the final rule to maintain their rights of first refusal to build a new transmission facility that is: (1) located entirely within the provider's franchised service territory; and (2) identified by the provider as needed to satisfy NERC reliability standards – even if that facility is selected in a regional transmission plan for purposes of cost allocation. And because a transmission provider would have retained its authority to address reliability issues in its franchised service territory, the final rule would not have needed its blanket waiver of penalties in the event that a competitor fails to fix a reliability issue.[3]

Had we allowed all reliability projects within a franchised service territory to retain a right of first refusal, this Commission would have emphasized its commitment to reliability. An incumbent transmission provider should be responsible for reliability needs in its franchised territory without regard to cost allocation. And by granting a blanket waiver of penalties, the final rule could be placing the Commission in a difficult position if a blackout results in widespread loss of power, and we are unable to assess a penalty.

My approach also would have encouraged transmission owners to seek regional cost allocation for their own local projects as a way of balancing regional costs. Such a balancing of projects could help ensure that all the parts of a region receive benefits that are at least roughly equivalent. Yet under the final rule, local projects that have their costs assigned regionally generally cannot maintain a right of first refusal, thus

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[2] Section III.B.3.d of the final rule, at PP 318-319.

[3] For a description of the blanket waiver, see section III.B.4.b of the final rule, at P 344 ("Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.")

discouraging transmission owners from seeking regional cost allocation for their local projects. For this reason, instead of encouraging more regional cooperation, the rule could ultimately discourage such cooperation by encouraging more local transmission projects.

In addition to my concerns regarding reliability, this Commission should have clarified that it was willing to protect the energy markets against misuse of the right of first refusal. That is, the Commission should have emphasized that a right of first refusal in a Commission-jurisdictional tariff is not license to effectively block, or endlessly delay building, a project that would efficiently and cost effectively provide significant benefits to a transmission network. While an incumbent utility with a right of first refusal is entitled to have the ability to exercise its initial right to develop a project, if it decides not to construct, the opportunity to construct the project and thus improve the power grid should be available to a non-incumbent developer.

A review of the transmission projects that have been adopted in various regional plans indicates that most projects will be allowed to retain the right of first refusal under the final rule, as most projects involve upgrades to existing assets, or they are built on an existing right of way, or their costs are not allocated to other transmission providers.[4] Thus, given the extensive number of projects that will be allowed to retain a right of first refusal, the Commission should have emphasized that a transmission provider cannot use a Commission-jurisdictional[5] tariff to prevent the lowest-cost power from reaching consumers.

Recognizing that no party to this proceeding asserted that a right of first refusal grants its holder a right to refuse building a project forever, I believe that a federal right of first refusal must be exercised within a reasonable time frame. The record in this case suggests that 90 days is a reasonable time frame for management to make a decision on

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[4] For a list of transmission projects that have been approved in PJM, see the various plans for PJM, and a comprehensive list available at: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx. And see Chapter 8 of CAISO's transmission plan for 2010-2011 dated May 18, 2011, available at: http://www.caiso.com/Documents/Board-approvedISO2010-2011TransmissionPlan.pdf.

[5] Consistent with the remainder of the rule, any time limitation on a right of first refusal under my approach would be subject to relevant state and other law concerning property rights, contracts, utility franchises, zoning, siting, permitting, easements, or rights of way. *See* section III.B.2.c of the final rule, at P 287.

whether to exercise its right to build a project.[6] While adoption of a 90-day time frame for transmission providers need not have been mandated, the Commission should have encouraged every region to adopt a time frame that best reflects the needs and circumstances of that region.[7]

In conclusion, new transmission lines can sometimes be the lowest-cost way to improve the delivery of electricity. By building needed transmission, our nation's transmission network can be maintained at reliability levels that are the envy of the world, while simultaneously improving consumer access to lower-cost power generation. Plus, a well-designed transmission network can allow efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power. While this rule moves us forward to achieve those goals, a different approach would have been better on the issues described above.

_____

Philip D. Moeller
Commissioner

[6] Comments of Southwest Power Pool at 14-27; AEP Comments at 3, 19; Comments of Edison Electric Institute at 46-47, Comments of Iberdrola Renewables at 23-24; Comments of Indianapolis Power & Light at 32; MidAmerican Comments at 24; Comments of MISO Transmission Owners at 73; Comments of Oklahoma Gas and Electric Co., at 1, 12, 25; SCE Comments at 41-43; PSEG Reply Comments at 12; Westar Comments at 6; Comments of ITC Companies at 4, 22; Comments of CapX2020 Utilities at 11, where the CapX2020 Utilities consist of Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Co., Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy Inc. In contrast to these comments on a 90-day time limit, LS Power and NextEra object to any right of first refusal and state that a 90-day limitation does not resolve their objections. LS Power Comments at 14-18 and fn. 20; LS Power Reply Comments at 10, 34-35; and NextEra Comments at 16.

[7] For example, in the case of the SPP region, the regional transmission organization will designate another company to build a project if the incumbent decides not to build within 90 days. Comments of Southwest Power Pool at 14-27.

187 FERC ¶ 61,068
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM21-17-000; Order No. 1920]

# Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

(Issued May 13, 2024)

**AGENCY**: Federal Energy Regulatory Commission.

**ACTION**: Final rule.

**SUMMARY**: The Federal Energy Regulatory Commission (Commission) revises the *pro forma* Open Access Transmission Tariff (OATT) to remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements. In this final rule, the Commission requires transmission providers to conduct Long-Term Regional Transmission Planning that will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs. The Commission also directs other reforms to improve coordination of regional transmission planning and generator interconnection processes, require consideration of certain alternative transmission technologies in regional transmission planning processes, and improve transparency of local transmission planning processes and coordination between regional and local transmission planning processes. These reforms are intended to ensure that existing regional and local transmission planning and cost allocation

requirements are just, reasonable, and not unduly discriminatory or preferential.

**EFFECTIVE DATE**: This final rule will become effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

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**SUPPLEMENTARY INFORMATION**:

187 FERC ¶ 61,068
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Willie L. Phillips, Chairman;
Allison Clements and Mark C. Christie.

| | | |
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| Building for the Future Through Electric Regional Transmission Planning and Cost Allocation | Docket No. | RM21-17-000 |

# ORDER NO. 1920

## FINAL RULE

(Issued May 13, 2024)

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## I. Introduction and Background

1. In this final rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements.[1] The reforms herein will remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements to ensure that the rates, terms, and conditions for transmission service provided by public utility transmission providers (transmission providers)[2] remain just and reasonable and not

[1] 16 U.S.C. 824e.

[2] Section 201(e) of the FPA, 16 U.S.C. 824(e), defines "public utility" to mean "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." As stated in the Order No. 888 *pro forma* Open Access Transmission Tariff (OATT), "transmission provider" is a "public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002); *Pro forma* OATT section I.1 (Definitions). The

unduly discriminatory or preferential. This final rule builds upon Order No. 888, Order No. 890,[3] and Order No. 1000,[4] in which the Commission incrementally developed the requirements that govern regional transmission planning and cost allocation processes to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. Specifically, in this final rule, we find that there is substantial evidence to support the conclusion that the existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs;[5] (2) adequately account on a forward-looking basis for known

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term "transmission provider" includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO).

[3] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, 118 FERC ¶ 61,119 (2007), *order on reh'g,* Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification,* Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[4] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[5] All capitalized terms are defined below. *Infra* Use of Terms section.

determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. Accordingly, we believe that it is necessary to revisit existing transmission planning and cost allocation requirements. We conclude that adopting the reforms of this final rule, as previously contemplated in the Notice of Proposed Rulemaking,[6] will remedy the identified deficiencies in existing regional and local transmission planning and cost allocation requirements, as discussed below, and will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

2. Specifically, the reforms adopted in this final rule require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[7] This final rule adopts specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning, including, among other things, the use of

[6] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028 (2022) (NOPR); *see also Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 27, 2021), 176 FERC ¶ 61,024 (2021) (ANOPR).

[7] For purposes of this final rule, and consistent with Order No. 1000, a transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 160.

scenarios to identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs.

3. This final rule also requires transmission providers to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning. In addition, this final rule requires transmission providers to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities and requires that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[8]

4. This final rule requires transmission providers to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.

5. Further, this final rule requires transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods to allocate the costs of

[8] We recognize that some transmission planning regions may include Long-Term Regional Transmission Facilities, or a portfolio of such Facilities, in a regional transmission plan, but may not necessarily include these Facilities for purposes of cost allocation. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 63. For purposes of this final rule, unless otherwise noted, when referencing Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected, we intend "selected" to mean that those Facilities are selected in the regional transmission plan for purposes of cost allocation.

Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected. This final rule further permits, but does not require, transmission providers to adopt a State Agreement Process, wherein Relevant State Entities agree to such a State Agreement Process that would provide up to six months after selection for its participants to determine, and transmission providers to file, a cost allocation method for specific Long-Term Regional Transmission Facilities. This final rule establishes a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities.

6. This final rule also requires transmission providers to include in their OATTs a process to provide Relevant State Entities and interconnection customers the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria. This final rule requires transmission providers to include in their OATTs provisions that require transmission providers—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected.

7. In addition, this final rule requires that transmission providers evaluate for potential selection in their existing Order No. 1000 regional transmission planning processes regional transmission facilities that will address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades[9] originally identified through the generator interconnection process.

8. This final rule requires transmission providers in each transmission planning region to consider more fully the alternative transmission technologies of dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning and cost allocation processes.

9. This final rule does not finalize the NOPR proposal to not permit transmission providers to take advantage of the recovery of 100% of construction work in progress for Long-Term Regional Transmission Facilities, and the Commission will instead continue to consider transmission incentives issues in other proceedings. This final rule similarly

[9] The Commission's *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) provide that, "Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." *See Improvements to Generator Interconnection Procedures & Agreements*, Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at P 13 n.23, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199 (2024). In this final rule, we refer to network upgrades developed through the generator interconnection process as interconnection-related network upgrades.

does not finalize the NOPR proposal with respect to permitting the exercise of federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the federal right of first refusal establishing joint ownership of the transmission facilities, and the Commission will instead continue considering the NOPR proposal and potential federal right of first refusal issues in other proceedings.

10. This final rule adopts the NOPR proposal to require transmission providers to adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities.

11. This final rule requires transmission providers to revise their interregional transmission coordination processes to reflect the Long-Term Regional Transmission Planning reforms adopted in this final rule. This final rule also requires that transmission providers meet additional information sharing and transparency requirements with respect to their interregional transmission coordination processes.

12. This final rule requires that each transmission provider submit a compliance filing within ten months of the effective date of this final rule revising its OATT and other document(s) subject to the Commission's jurisdiction to demonstrate that it meets the requirements of this final rule, with the exception of those requirements adopted in the Interregional Transmission Coordination section in this final rule. This final rule requires that each transmission provider submit a compliance filing within 12 months of the effective date of this final rule revising its OATT and other document(s) subject to the

Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final rule.

13. We recognize that transmission providers have ongoing efforts to address transmission planning and cost allocation. This final rule is not intended to interfere with the potential progress represented by those efforts, and we encourage transmission providers to continue to innovate to improve their transmission planning and cost allocation processes.

### A. Historical Framework: Order Nos. 888, 890, and 1000

14. Over the last several decades, the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000. In 1996, the Commission issued Order No. 888, which implemented open access to transmission facilities owned, operated, or controlled by a public utility and included certain minimum requirements for transmission planning. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT after more than 10 years of experience since Order No. 888. Among other OATT reforms, the Commission required all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[10]

[10] Order No. 890, 118 FERC ¶ 61,119 at PP 418-601.

15. In 2011, the Commission recognized the need for further transmission planning reforms with its issuance of Order No. 1000. The Commission based the reforms it adopted in Order No. 1000 on changes in the energy industry, its experience implementing Order No. 890, and a robust record developed through technical conferences and comments from a diverse range of stakeholders.[11] The Commission stated in Order No. 1000 that "the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost."[12] In establishing the requirements of Order No. 1000, the Commission found that the existing requirements of Order No. 890 were not adequate, noting that Order No. 1000 "expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters."[13] The Commission then enumerated multiple concerns that it had regarding existing transmission planning practices, including concerns about: (1) the lack of an affirmative obligation to develop a transmission plan evaluating if a regional transmission facility "may be more efficient or cost-effective than solutions identified in local transmission planning processes"; (2) the lack of a

[11] For purposes of this final rule, and consistent with Order No. 1000, a stakeholder includes any party interested in the transmission planning processes. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 151 n.143.

[12] *Id.* P 2.

[13] *Id.* P 21.

requirement to address Public Policy Requirements;[14] (3) the federal right of first refusal for incumbent transmission developers to build upgrades to their existing transmission facilities; (4) the lack of procedures to identify and evaluate the benefits of interregional transmission facilities; and (5) cost allocation for regional and interregional transmission facilities.[15]

16. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the *pro forma* OATT could support the development of more efficient or cost-effective transmission facilities.[16] The reforms in Order No. 1000 included: (1) regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost allocation, including a set of principles for each category of cost allocation; and (5) interregional transmission coordination. The reforms focused on the process by which transmission providers engage in regional

[14] Public Policy Requirements are requirements established by local, state, or federal laws or regulations (i.e., enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level). *Id.* P 2. Order No. 1000-A clarified that Public Policy Requirements include local laws or regulations passed by a local governmental entity, such as a municipal or county government. Order No. 1000-A, 139 FERC ¶ 61,132 at P 319.

[15] Order No. 1000, 136 FERC ¶ 61,051 at P 3.

[16] *Id.* PP 11-12, 42-44; Order No. 1000-A, 139 FERC ¶ 61,132 at PP 3, 4-6.

transmission planning and the associated cost allocation rather than on the outcomes of the process.[17]

17. Among other regional transmission planning reforms in Order No. 1000, the Commission required that the following Order No. 890 transmission planning principles apply to regional transmission planning processes: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.[18]

18. In addition, with respect to the Order No. 1000 reforms, the Commission made a distinction between a transmission facility "included" in a regional transmission plan and a transmission facility "selected." A transmission facility selected in a regional transmission plan for purposes of cost allocation is a transmission facility that has been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective transmission facility needed to meet regional transmission needs. Both regional transmission facilities and interregional transmission facilities are eligible for potential "selection" in a regional transmission plan for purposes of cost allocation.[19]

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[17] Order No. 1000, 136 FERC ¶ 61,051 at P 12.

[18] The Commission did not include the regional participation or cost allocation transmission planning principles with respect to regional transmission planning processes because those issues were addressed by other reforms in Order No. 1000. *Id.* P 151.

[19] *Id.* P 63. A regional transmission facility and an interregional transmission

19. Selected transmission facilities often will not comprise all of the transmission facilities that are included in a regional transmission plan.[20] Some transmission facilities are merely "rolled up" and listed in a regional transmission plan without going through an analysis at the regional level, and/or are merely considered for reliability implications upon a transmission system, and therefore, are not eligible for selection and regional cost allocation.[21] For example, a local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected.[22] Thus, a local transmission facility may be rolled up and "included" in a regional transmission plan for informational purposes, but it is not "selected."

### B. ANOPR and Technical Conference

20. In July 2021, the Commission issued the ANOPR[23] presenting potential reforms to improve the regional transmission planning and cost allocation and generator interconnection processes. In issuing the ANOPR, the Commission noted that, in part

facility are defined below. *Infra* Use of Terms section.

[20] Order No. 1000, 136 FERC ¶ 61,051 at P 63.

[21] *Id.* PP 7, 226, 318.

[22] *Id.* P 63. The Commission clarified in Order No. 1000-A that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider's retail distribution service territory, if it has one; otherwise, the area is defined by the public utility transmission provider's footprint. In the case of an RTO/ISO whose footprint covers the entire region, a local transmission facility is defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members. Order No. 1000-A, 139 FERC ¶ 61,132 at P 429.

[23] ANOPR, 176 FERC ¶ 61,024.

because more than a decade had passed since Order No. 1000, it was now an appropriate time to review its regulations governing regional transmission planning and cost allocation to determine whether reforms are needed to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.[24] The Commission noted that the electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources that may often be located far from load centers. The Commission also highlighted the growth of new resources seeking to interconnect to the transmission system and that the differing characteristics of those resources are creating new demands on the transmission system. The Commission explained that ensuring just and reasonable Commission-jurisdictional rates during these changes, while maintaining grid reliability, remains the Commission's priority in adopting requirements for the regional transmission planning and cost allocation and generator interconnection processes. As a result, the Commission issued the ANOPR to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained.

21. On November 15, 2021, the Commission convened a staff-led technical conference (November 2021 Technical Conference or Technical Conference) to examine in detail issues and potential reforms related to regional transmission planning as

[24] *Id.* P 3.

described in the ANOPR. Specifically, the Technical Conference included three panels covering issues to consider in long-term scenarios, consideration of long-term scenarios in regional transmission planning processes, and identifying geographic zones with high renewable resource potential for use in regional transmission planning processes.[25] Following the Technical Conference, the Commission invited all interested persons to file comments to address issues raised during the Technical Conference.

### C. Joint Federal-State Task Force on Electric Transmission

22. On June 17, 2021, the Commission established a Joint Federal-State Task Force on Electric Transmission (Task Force) to formally explore broad categories of transmission-related topics.[26] The Commission explained that the development of new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Given that federal and state regulators each have authority over transmission-related issues and given the impact of transmission infrastructure development on numerous different priorities of federal and state regulators, the Commission determined that the topic was ripe for greater federal-state coordination and cooperation.[27] The Task Force was composed of all sitting FERC Commissioners as well

[25] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Further Supplemental Notice of Technical Conference, Docket No. RM21-17-000 (issued Nov. 12, 2021) (attaching agenda).

[26] *Joint Fed.-State Task Force on Elec. Transmission*, 175 FERC ¶ 61,224, at PP 1, 6 (2021).

[27] *Id.* P 2.

as representatives from 10 state commissions nominated by the National Association of Regulatory Utility Commissioners (NARUC), with two originating from each NARUC region.[28]

23. The Task Force has convened multiple formal meetings with eight meetings held thus far to discuss regional transmission planning and cost allocation issues, convening on November 10, 2021, February 16, 2022, May 6, 2022, July 20, 2022, November 15, 2022, February 15, 2023, July 16, 2023, and February 28, 2024.

24. The discussion at the November 2021 meeting was focused on incorporating state perspectives into regional transmission planning.[29] The February 2022 meeting included discussion of specific categories and types of transmission benefits that transmission providers should consider for the purposes of transmission planning and cost allocation.[30] The May 2022 meeting focused on barriers to the efficient, expeditious, and reliable interconnection of new resources.[31] The July 2022 meeting focused on interregional

[28] An up-to-date list of Task Force members, as well as additional information on the Task Force, is available on the Commission's website at: https://www.ferc.gov/TFSOET. Public materials related to the Task Force, including transcripts from public meetings, are available in the Commission's eLibrary in Docket No. AD21-15-000.

[29] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Oct. 27, 2021) (attaching agenda).

[30] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 2, 2022) (attaching agenda).

[31] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Apr. 22, 2022) (attaching agenda).

transmission planning and transmission project development and the NOPR.[32] The November 2022 meeting focused on regulatory gaps and challenges in oversight of transmission development.[33] The February 2023 meeting focused on the physical security of the nation's transmission system, and featured guest speakers from the North American Electric Reliability Corporation and US DOE.[34] The July 2023 meeting focused on grid enhancing technologies, featuring a guest speaker from the Electric Power Research Institute.[35] The February 2024 meeting focused on transmission siting, featuring guest speakers from US DOE.[36]

25. In light of the Task Force expiring three years from its first public meeting, i.e., on November 10, 2024,[37] on March 21, 2024, the Commission established the Federal and State Current Issues Collaborative (Collaborative).[38] The Collaborative will be comprised of all Commissioners, as well as representative from 10 state commissions.

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[32] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued June 30, 2022) (attaching agenda).

[33] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Nov. 1, 2022) (attaching agenda).

[34] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 1, 2023) (attaching agenda).

[35] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued June 30, 2023) (attaching agenda)

[36] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 13, 2024) (attaching agenda)

[37] *Joint Fed.-State Task Force on Elec. Transmission*, 175 FERC ¶ 61,224 at P 4.

[38] *Joint Fed.-State Task Force on Elec. Transmission*, 186 FERC ¶ 61,189 (2024).

The Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and where appropriate, identify potential solutions regarding challenges and coordination on matters that impact specific state and federal regulatory jurisdiction.[39]

### D. Notice of Proposed Rulemaking

26. On April 21, 2022, the Commission issued the NOPR, proposing reforms focused on long-term regional transmission planning and cost allocation processes. In particular, the Commission proposed in the NOPR that transmission providers in each transmission planning region participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[40] The Commission also proposed to require that transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[41]

27. The Commission proposed that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the relevant interconnection request(s).[42]

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[39] *Id.* PP 5-6.

[40] NOPR, 179 FERC ¶ 61,028 at PP 64, 68.

[41] *Id.* P 84.

[42] *Id.* P 166.

28. The Commission proposed 12 benefits that transmission providers may consider in Long-Term Regional Transmission Planning and cost allocation processes.[43] The Commission stated that the list of potential benefits was neither mandatory nor exhaustive, and that pursuant to the proposal, transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.[44]

29. The Commission proposed, with regard to the selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation, to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs: (1) transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection that address transmission needs driven by changes in the resource mix and demand; and (2) a process to coordinate with the Relevant State Entities in developing such criteria.[45]

30. The Commission proposed to require transmission providers to more fully consider the incorporation into transmission facilities of dynamic line ratings and

[43] *Id.* P 185.

[44] *Id.* P 184.

[45] *Id.* P 241.

advanced power flow control devices in regional transmission planning and cost allocation processes.[46]

31. The Commission proposed to require, with regard to allocating the costs of Long-Term Regional Transmission Facilities, transmission providers to revise their OATTs to include: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method; or (3) a combination thereof.[47] The Commission proposed to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[48] The Commission proposed to require transmission providers to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.[49]

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[46] *Id.* P 272.

[47] *Id.* P 302.

[48] *Id.* P 303.

[49] *Id.* P 326.

32. The Commission further proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of construction work in progress costs in rate base in certain circumstances for Long-Term Regional Transmission Facilities.[50]

33. Finally, the Commission proposed to permit the exercise of federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.[51]

34. The Commission also proposed to require transmission providers to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[52] The Commission proposed to require transmission providers to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10

[50] *Id.* P 333.

[51] *Id.* P 351.

[52] *Id.* P 400.

years can be "right-sized" to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning.[53]

35. The Commission further proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.[54] Finally, the Commission proposed to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.[55]

[53] *Id.* P 403.

[54] *Id.* P 427.

[55] *Id.* P 428.

### E. High-Level Overview of NOPR Comments

36. The Commission received a great many comments from a diverse set of parties in response to the NOPR.[56] One hundred and ninety-six parties, including federal agencies, state regulatory commissions, state policy makers and other state representatives, ratepayer advocates, municipalities, RTOs/ISOs, RTO/ISO market monitors, transmission providers, transmission-dependent utilities, electric cooperatives, municipal power providers, independent power producers, transmission developers, generation trade associations, transmission trade associations, industry interest groups, consumer interest groups, energy policy and law interest groups, individual businesses, landowners, and individuals, filed initial comments that totaled over 15,000 pages with attachments. A similarly diverse set of 92 parties filed reply comments that totaled nearly 1,900 pages.

### F. Use of Terms

37. Before turning to the detailed requirements of this final rule, we note several of the key terms used herein. We further address the definitions of these terms, including any modifications to definitions proposed in the NOPR, in the relevant later sections of this final rule.

38. For purposes of this final rule, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission

[56] *See* Appendix A for a list of commenters and the abbreviated names of commenters that are used in this final rule.

facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

39. For purposes of this final rule, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors.[57]

40. For purposes of this final rule, Long-Term Scenarios are scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs.

41. For purposes of this final rule, a Long-Term Regional Transmission Facility is a regional transmission facility[58] that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.

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[57] Further discussion on Long-Term Transmission Needs can be found below. *Infra* Development of Long-Term Scenarios subsection under the Long-Term Regional Transmission Planning section.

[58] For purposes of this final rule, and consistent with Order No. 1000, a regional transmission facility is a transmission facility located entirely in one transmission planning region. An interregional transmission facility is a transmission facility that is located in two or more transmission planning regions. A local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for

42. For purposes of this final rule, best available data inputs are data inputs that are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000, and reflect the list of factors that transmission providers account for in their Long-Term Scenarios.

43. For purposes of this final rule, a Long-Term Regional Transmission Cost Allocation Method is an *ex ante* regional cost allocation method for one or more selected Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation.

44. For purposes of this final rule, a Relevant State Entity is any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.

45. For purposes of this final rule, a State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected.

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purposes of cost allocation. Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 482 n.374.

46. For purposes of this final rule, federally-recognized Tribes are those Tribes listed in the most recent notice provided by the Bureau of Indian Affairs and published in the *Federal Register*.[59]

## II. The Overall Need for Reform

### A. NOPR Proposal

47. The Commission issued the NOPR on April 21, 2022, proposing to reform the *pro forma* OATT and the *pro forma* LGIA to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements. The Commission stated that, over the last 25 years, it has undertaken a series of significant reforms to ensure that transmission planning and cost allocation processes result in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.[60] The Commission noted that it has now been more than a decade since Order No. 1000—its last significant regional transmission planning and cost allocation rule—and that there is mounting evidence that its regional transmission planning and cost allocation requirements may be inadequate to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.[61]

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[59] *See, e.g.*, *Indian Entities Recognized by and Eligible to Receive Servs. from the U.S. Bureau of Indian Affairs*, *Federal Register*, 89 FR 944 (Jan. 8, 2024).

[60] NOPR, 179 FERC ¶ 61,028 at P 24.

[61] *Id.*

48. The Commission found that, in particular, although transmission providers are required to participate in regional transmission planning and cost allocation processes under Order No. 1000, it was concerned that those processes may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand. The Commission stated that, as a result, the regional transmission planning and cost allocation processes that transmission providers adopted to comply with Order No. 1000 may not be identifying the more efficient or cost-effective transmission facilities.[62] The Commission stated that it was concerned that the absence of sufficiently long-term, forward-looking, comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs, and that continuing with the status quo approach may cause transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. The Commission stated that this dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential. Based on the evidence, the Commission preliminarily concluded that revisions to its existing transmission planning and cost allocation requirements

[62] *Id.* PP 24-25.

established in Order Nos. 890 and 1000 are necessary to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory and preferential.[63]

### B. Comments

49. A significant majority of commenters, including transmission providers, transmission developers, transmission customers, members of Congress, states, state commissions, consumer advocates, trade associations, and public interest organizations, among others, agree that existing regional transmission planning and cost allocation processes need to be reformed.[64] Advanced Energy Buyers note that the electric system

[63] *Id.* PP 25, 27, 34-35.

[64] *See, e.g.*, Acadia Center and CLF Initial Comments at 1-2; ACEG Initial Comments at 11-12, 21-22; ACORE Initial Comments at 2-5; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 2-3; AEE Initial Comments at 7-8; AEP Initial Comments at 1-3; Amazon Initial Comments at 1-2; Ameren Initial Comments at 1-2; American Municipal Power Initial Comments at 4; Anbaric Initial Comments at 1; Arizona Commission Initial Comments at 3-4; Avangrid Initial Comments at 5-6; BP Initial Comments at 3; Breakthrough Energy Initial Comments at 5-6; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2-3; California Commission Initial Comments at 1-2; California Energy Commission Initial Comments at 1; CAISO Initial Comments at 1; City of New Orleans Council Initial Comments at 4, 7-9; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 4-5; US Senators Supplemental Comments at 1; EEI Initial Comments at 4-5; ELCON Initial Comments at 4; Enel Initial Comments at 2, 7; ENGIE Initial Comments at 1-2; Entergy Initial Comments at 2-3; Environmental Legislators Caucus Supplemental Comments at 1; Evergreen Action Initial Comments at 1-3; Eversource Initial Comments at 1-2, 5-9; Exelon Initial Comments at 1-2; Grid United Initial Comments at 1-2; Handy Law Initial Comments at 1-7; Harvard ELI Initial Comments at 1; Illinois Commission Initial Comments at 3; Indicted PJM TOs Initial Comments at 1-2; Indicated US Senators and Representatives Initial Comments at 1; Interwest Initial Comments at 2-3; Invenergy Initial Comments at 2, 5; ISO-NE Initial Comments at 2, 8-9; ISO/RTO Council Initial Comments at 2; Kansas Commission

is presently undergoing one of the most significant transformations in a century.[65] Other commenters agree that electric energy supply and demand is evolving quickly.[66] Clean Energy Buyers agree with the Commission that there is a need for reform to meet these drastic changes in the resource mix and load and to ensure continued reliability and cost-effective transmission service.[67]

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Initial Comments at 10-11; Massachusetts Attorney General Initial Comments at 3-6; Michigan Commission Initial Comments at 2, 4; Michigan State Entities Initial Comments at 3-4; Minnesota State Entities Initial Comments at 2-3; National Grid Initial Comments at 1, 6; National and State Conservation Organizations Initial Comments at 1; NESCOE Initial Comments at 2, 7, 14-15; New Jersey Commission Initial Comments at 1-2; New York Commission and NYSERDA Initial Comments at 1-3; NextEra Reply Comments at 1; Non-RTO NASUCA Initial Comments at 4-5; NYISO Initial Comments at 2-3; Onward Energy Initial Comments at 1-2; Ørsted Initial Comments at 2-3; Pattern Energy Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 2, 7-8; Pacific Northwest State Agencies Initial Comments at 1, 8; PG&E Initial Comments at 1; PIOs Initial Comments at 6-7; Policy Integrity Initial Comments at 1-2; Renewable Northwest Initial Comments at 3-4; RMI Supplemental Comments at 1-2; SPP Market Monitor Initial Comments at 3-4; SEIA Initial Comments at 2; Shell Initial Comments at 1, 9; US Senator Barrasso Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2; Southeast PIOs Initial Comments at 1; SREA Initial Comments at 1; State Officials Supplemental Comments at 1; TAPS Initial Comments at 1-2; US DOE Initial Comments at 1-4; US DOJ and FTC Initial Comments 1, 5; Vermont State Entities Initial Comments at 2; Western State Representatives Initial Comments at 3-4; WIRES Initial Comments at 2, 5.

[65] Advanced Energy Buyers Initial Comments at 2.

[66] *See, e.g.*, AEE Initial Comments at 1; Cross Sector Representatives Supplemental Comments at 1; Eversource Initial Comments at 5-8 (citing ISO-NE, *2020 Regional Electricity Outlook*, at 35 (2020)); Indicated PJM TOs Initial Comments at 1-2; Kansas Commission Initial Comments at 2; Pattern Energy Initial Comments at 1; PG&E Initial Comments at 1; Policy Integrity Initial Comments at 2; Renewable Northwest Initial Comments at 5; State Agencies Initial Comments at 12-13; WIRES Initial Comments at 3.

[67] Clean Energy Buyers Initial Comments at 7.

50. Many commenters argue that current regional transmission planning and cost allocation processes across the country are not ensuring efficient and cost-effective transmission development, are not satisfying the purposes of Order Nos. 890 and 1000, and are not meeting transmission needs at a reasonable cost. For example, several commenters assert that Order Nos. 890 and 1000 have not solved longstanding problems with regional transmission planning and cost allocation.[68] Northwest and Intermountain claim that Order No. 1000 has been inadequate to meet transmission needs, particularly in the non-RTO/ISO West.[69] Michigan State Entities assert that the current lack of long-term transmission planning has led to significantly higher costs for residential ratepayers, costs that will increase without reforms.[70] SREA argues that reform is needed to correct the unintended consequences of Order No. 1000 in the Southeast, where transmission planning "has grown into an enormously elaborate and extremely expensive black box," without any meaningful review by state regulatory bodies.[71]

[68] *See, e.g.*, Acadia Center and CLF Initial Comments at 1; ACEG Initial Comments at 17-18, 20 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3; NOPR, 179 FERC ¶ 61,028 at PP 24-25); AEE Initial Comments at 1-2; CARE Coalition Initial Comments at 3; NERC Initial Comments at 5; Massachusetts Attorney General Initial Comments at 5-6; Northwest and Intermountain Initial Comments at 6-7; Pine Gate Initial Comments at 8-10; PIOs Initial Comments at 2-3; Southeast PIOs Initial Comments at 7-9, 11, 16-17, 43-44; SPP Market Monitor Initial Comments at 3-4; SREA Reply Comments at 4; US DOE Initial Comments at 3-4, 7-8.

[69] Northwest and Intermountain Initial Comments at 6-7.

[70] Michigan State Entities Initial Comments at 1-2.

[71] SREA Reply Comments at 4.

51. PIOs assert that transmission owners can evade Order No. 1000 requirements through investments in local transmission projects, which has led to billions of dollars in excessive costs.[72] PIOs explain that financial incentives drive utilities to upgrade their own systems at the expense of building a more integrated and robust transmission system to meet the needs and demands of the future.[73] PIOs observe that, between 2013 and 2017, about one-half of the approximately $70 billion in aggregate transmission investments by Commission-jurisdictional transmission owners in RTO/ISO regions were approved outside of regional transmission planning processes or with limited stakeholder engagement.[74] Ohio Consumers add that since 2017, less than 25% of new transmission investments in Ohio have been associated with large regional transmission projects needed for reliability or economic efficiency.[75] Competition Coalition argues that incumbent transmission owners have used reliability designations to justify projects with higher costs.[76]

[72] PIOs Initial Comments at 8 (citing Johannes P. Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 19-20, and Section I (Apr. 2019) (Brattle Apr. 2019 Competition Report), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf).

[73] *Id.* at 6-7.

[74] *Id.* at 9 (citing Brattle Apr. 2019 Competition Report at 4).

[75] Ohio Consumers Initial Comments at 5.

[76] Competition Coalition Initial Comments at 15-16.

52. Citing to a report from Lawrence Berkeley National Laboratory, US DOE concludes that many existing regional transmission planning approaches are likely understating the economic value of new transmission. US DOE suggests that the need for increased transmission capacity to address persistent and worsening transmission congestion demonstrates that these processes may not fully anticipate present and future transmission needs.[77] In addition, US DOE notes the unfair burden on interconnection customers that must bear increasing costs, especially for interconnection-related network upgrades that provide system-wide benefits.[78] US DOJ and FTC agree that reforms are necessary to encourage needed regional and interregional transmission investment and that a larger, more integrated transmission system would improve resilience, promote competition, and lower costs for consumers.[79]

53. Many commenters contend that inadequate regional transmission planning and cost allocation processes have resulted in, or are threatening to cause, unjust, unreasonable, and unduly discriminatory or preferential rates.[80] Michigan State Entities

[77] US DOE Initial Comments at 3-4.

[78] *Id.* at 7-8.

[79] US DOJ and FTC Initial Comments at 1, 5 (citing NOPR, 179 FERC ¶ 61,028 at P 6; P. R. Brown & A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115, 115-134 (2021); Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 108 (Oct. 2021), https://netzeroamerica.princeton.edu/the-report).

[80] *See, e.g.*, ACORE Initial Comments at 3, AEE Initial Comments at 27 (citing NOPR, 179 FERC ¶ 61,028 at PP 47, 55, 78; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56); CARE Coalition Initial Comments at 17; Certain TDUs Initial Comments at 2; Clean

cite renewable energy curtailments, which limit the supply of energy that customers can access, and the lack of regional and interregional transmission lines, which limit the transfer of lower-priced power.[81] New Jersey Commission asserts that better transmission planning can reduce overall system costs by billions of dollars.[82] Certain TDUs add that Commission action is essential now to ensure that necessary transmission expansion occurs in a way that protects customers from excessive costs and that results in just and reasonable transmission rates.[83] CARE Coalition argues that the Commission's current failure to require transmission planners to internalize siting-related costs and risks results in unjust, unreasonable, and unduly discriminatory or preferential rates.[84] In a similar vein, Ørsted and Massachusetts Attorney General claim that failure to proactively plan for offshore wind generation buildout could lead to transmission rates that are unjust, unreasonable, and unduly discriminatory or preferential.[85]

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Energy Associations Initial Comments at 3, 7; Clean Energy Buyers Initial Comments at 10; Harvard ELI Initial Comments at 1; Massachusetts Attorney General Initial Comments at 5-6; New Jersey Commission Initial Comments at 1-2; PIOs Initial Comments at 6; SEIA Initial Comments at 2-3; Southeast PIOs Reply Comments at 2; US DOE Initial Comments at 2, 6-7.

[81] Michigan State Entities Initial Comments at 3.

[82] New Jersey Commission Initial Comments at 3-9.

[83] Certain TDUs Initial Comments at 2.

[84] CARE Coalition Initial Comments at 17.

[85] Massachusetts Attorney General Initial Comments at 5; Ørsted Initial Comments at 3-5.

54. Several commenters agree with the Commission's concerns that the expansion of the high-voltage transmission system is increasingly occurring outside of the regional transmission planning process through other mechanisms such as the generator interconnection process, which results in piecemeal transmission development.[86] AEE agrees that limited development of regional transmission facilities, increased spending on local transmission projects, and backlogged interconnection queues all show that the existing regional transmission planning requirements are not sufficient to meet customers' transmission needs.[87] Likewise, Exelon argues that relying on interconnection studies as the primary transmission planning method results in piecemeal and inefficient transmission investment.[88] PIOs add that many generation developers have to bear the full costs of transmission upgrades, which leads to interconnection request withdrawals, inefficiencies, and higher system-wide costs.[89] In addition, Clean Energy States note that interconnection queues are extremely large and that the current

[86] *See, e.g.*, Acadia Center and CLF Initial Comments at 3-4; Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 4-7; Exelon Initial Comments at 1-2, 5; Joint Consumer Advocates Initial Comments at 5; Non-RTO NASUCA Initial Comments at 4; Ørsted Initial Comments at 4-5; Pine Gate Initial Comments at 8-10; SEIA Initial Comments at 2; *see also* AEP Initial Comments at 8.

[87] AEE Initial Comments at 1-2 (citing NOPR, 179 FERC ¶ 61,028 at PP 47-55).

[88] Exelon Initial Comments at 5.

[89] PIOs Initial Comments at 9-10.

one-plant-at-a-time approach to transmission upgrades drives up costs and misses opportunities for improvements to the system as a whole.[90]

55. Non-RTO NASUCA agrees with the Commission that Long-Term Regional Transmission Planning is necessary to help alleviate generation interconnection issues.[91] According to Harvard ELI, current transmission planning processes have failed to address backlogged interconnection queues and operational challenges that are best addressed at the regional level, as well as to include inexpensive technologies that can increase transmission capacity.[92]

56. ACEG argues that there is no evidence that any regional reliability or economic transmission planning performed in non-RTO/ISO regions, like the Southeastern Regional Transmission Planning region (SERTP), is equal to or superior to the techniques or outcomes in the NOPR.[93] ACEG further contends that, instead, most new transmission facilities built since Order No. 1000 have been built for local transmission needs, thereby resulting in less efficient and cost-effective transmission development that does not address the larger needs of the transmission system for reliability and

[90] Clean Energy States Initial Comments at 2.

[91] Non-RTO NASUCA Initial Comments at 4.

[92] Harvard ELI Initial Comments at 1.

[93] ACEG Reply Comments at 9 (citing Alabama Commission Initial Comments at 2-3; Southern Initial Comments at 5-6, Ex. 2 at 2-3).

resilience.[94] Relatedly, SREA states that no state fully participates in SERTP, and that instead, each state in the Southeast uses its own state planning process, with no platform for states to collaborate. As a result, SREA argues that "transmission planning in the Southeast has many holes and is threadbare."[95] SREA catalogs deficiencies in many Southeastern states' planning processes, including a lack of transparency.[96]

57. Western PIOs argue that, outside of CAISO, transmission planning in the West is ineffective.[97] Specifically, Western PIOs assert that Western transmission planning groups have not developed new transmission projects using their Order No. 1000 transmission planning processes, but have instead built transmission projects that their utility members have already proposed.[98] Relatedly, SEIA argues that "non-RTO areas do not engage in sufficient or transparent transmission planning," and that transmission planning in non-RTO/ISO regions is exclusionary, based on inconsistent and inaccurate data, and disjointed.[99] More broadly, NRECA contends that incumbent investor-owned utilities control transmission planning, and that some incumbent investor-owned utilities

[94] *Id.* at 9-10 (citing PIOs Initial Comments at 7).

[95] SREA Reply Comments at 4.

[96] *Id.* at 5-18.

[97] Western PIOs Initial Comments at 4-28.

[98] *Id.* at 28.

[99] SEIA Reply Comments at 5-6 (citing Southern Initial Comments at 13-14).

develop transmission without transparency, leading to disparities in transmission rates in different RTO/ISO local zones.[100]

58. Several commenters specify other reasons that transmission planning reforms are needed.[101] Americans for Fair Energy Prices agree with PIOs that there is a need for regional transmission planning instead of the balkanized process that currently exists.[102] DC and MD Offices of People's Counsel assert that the NOPR provides a once-in-a-generation opportunity to meet the energy transition in a just, equitable, efficient, reliable, and resilient fashion by recognizing the benefits of long-term transmission planning and developing rules that incorporate those broad benefits. DC and MD Offices of People's Counsel state that current transmission planning processes do not fully consider all of the benefits of transmission development, including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather.[103] ACEG argues that current transmission planning processes have not led to investment in interregional transmission capacity, and that more interregional transmission capacity could have avoided some of the $25 billion to $70 billion in yearly costs caused by severe

[100] NRECA Initial Comments at 15-16.

[101] *See, e.g.*, Americans for Fair Energy Prices Reply Comments at 5; SREA Reply Comments at 4.

[102] Americans for Fair Energy Prices Reply Comments at 5 (citing PIOs Initial Comments at 34).

[103] DC and MD Offices of People's Counsel Reply Comments at 1-2.

weather events.[104] EEI states that robust transmission development will provide a host of benefits for customers, including greater resilience, enhanced system reliability, and cost-savings from greater access to low-cost resources.[105] Some commenters emphasize the importance of the Commission taking prudent action to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements,[106] and to strengthen electric reliability and resilience, while controlling costs.[107]

59. Several commenters argue that the need to reform transmission planning includes addressing environmental justice and equity issues.[108] Center for Biological Diversity states that energy justice and environmental justice considerations are appropriately

[104] ACEG Initial Comments at 21-22 (citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather*, at 1-3, 12 (July 2021) (Grid Strategies July 2021 Extreme Weather Report)).

[105] EEI Supplemental Comments at 1.

[106] US Senators Supplemental Comments at 1; Senator Whitehouse Supplemental Comments at 2.

[107] US Senator Barrasso Supplemental Comments at 1-2.

[108] *See, e.g.*, CARE Coalition Initial Comments at 2; Center for Biological Diversity Initial Comments at 20-24; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Grand Rapids NAACP Initial Comments at 20-21; Massachusetts Attorney General Initial Comments at 53-54 (citing Massachusetts Attorney General ANOPR Initial Comments at 32-34); Montclair Congregation Supplemental Comments at 1; NESCOE Reply Comments at 8-9; New England for Offshore Wind Initial Comments at 5; PIOs Reply Comments at 11-17; US DOE Initial Comments at 9; WE ACT Initial Comments at 1-2.

included in transmission planning.[109] Center for Biological Diversity further asserts that it is within the Commission's authority to consider these costs and benefits, as the benefits of decarbonization and related energy justice objectives will be far greater than the costs.[110] Grand Rapids NAACP, CARE Coalition, and PIOs argue that to ensure just, reasonable, and nondiscriminatory rates, transmission planning must consider energy equity and environmental justice.[111] Grand Rapids NAACP further argues that high energy burdens can be unjust, unreasonable, and unduly discriminatory or preferential.[112] Grand Rapids NAACP argues that the Commission's duty under the FPA to promote the public interest requires it to ensure that energy justice and equity considerations are included in transmission planning processes.[113] WE ACT relatedly argues that, due to under-investment, the transmission system is unreliable and vulnerable to extreme

[109] Center for Biological Diversity Initial Comments at 20-24 (citing Pacific Northwest National Laboratory & Sandia National Laboratories, *Advancing Energy Equity in Grid Planning* (Apr. 2022), https://netl.doe.gov/sites/default/files/netl-file/Advancing%20Energy%20Equity%20in%20Grid%20Planning.pdf; Office of Energy Justice and Equity, US DOE, *Justice40 Initiative*, https://www.energy.gov/diversity/justice40-initiative).

[110] *Id.* at 23 (citing *Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 942 (8th Cir. 2020)).

[111] Grand Rapids NAACP Reply Comments at 4 (citing 16 U.S.C. 824(a); *Re Nat'l Ass'n for the Advancement of Colored People, Inc.*, 95 P.U.R.3d 357 (F.P.C. 1972), *vacated and remanded sub nom. NAACP v. FPC*, 520 F.2d 432 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976)); CARE Coalition Initial Comments at 2; PIOs Reply Comments at 14.

[112] *Id.* at 20-21.

[113] *Id.* at 17-19.

weather events, which is both a reliability and environmental justice issue because communities of color and low-income communities are more susceptible to power outages during extreme weather.[114]

60. Advanced Energy Buyers state that failure to prepare the grid for the energy transition would be problematic for three primary reasons: (1) insufficient transmission investment will leave customer cost savings on the table; (2) lack of available transmission capacity will constrain its members' ability to meet decarbonization and clean energy goals; and (3) failure to plan and build adequate transmission will hamper the transition to a cleaner and more reliable electric grid.[115] New Jersey Commission contends that the lack of holistic multi-driver transmission planning is inflating consumers' electricity costs by billions of dollars every year.[116] Northwest and Intermountain explain that due to insufficient transmission capacity from renewable rich zones, utilities must attempt to meet their renewable energy policy targets with new resources that are close to load but more expensive, less reliable, and less efficient than more distant alternatives, even considering the potential costs of transmission expansion.[117] Clean Energy Associations add that the lack of transmission capacity imposes real and demonstrable costs today, as evidenced by geographic differences in

[114] WE ACT Initial Comments at 1-2.

[115] Advanced Energy Buyers Initial Comments at 3.

[116] New Jersey Commission Initial Comments at 2-9.

[117] Northwest and Intermountain Initial Comments at 6.

real-time power prices, and that the lack of robust and proactive transmission planning rules renders current rates unjust, unreasonable, and unduly discriminatory or preferential.[118]

61. Southeast PIOs contend that the "snowballing" inefficiencies created by numerous small-scale transmission "band-aids" result in unjust, unreasonable, and unduly discriminatory or preferential rates, and that reforms are particularly needed in the Southeast, where there is minimal utility coordination and a balkanized transmission system.[119] According to ACEG, short-term, piecemeal transmission planning is unlikely to identify the more efficient or cost-effective solutions to transmission needs and thus will result in unjust, unreasonable, and unduly discriminatory or preferential rates.[120]

62. Many commenters argue that reforms are necessary to meet state policy goals[121] and that greater state involvement or consideration of state policies is needed to avoid

[118] Clean Energy Associations Initial Comments at 5 (citing Dev Millstein et al., Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value Using Locational Marginal Prices*, at 3 (Aug. 2022), https://eta-publications.lbl.gov/sites/default/files/lbnlempirical_transmission_value_study-august_2022.pdf (LBNL Aug. 2022 Transmission Value Study)).

[119] Southeast PIOs Reply Comments at 1-2.

[120] ACEG Initial Comments at 21.

[121] *See, e.g.*, Acadia Center and CLF Initial Comments at 1; ACORE Reply Comments at 1; Breakthrough Energy Initial Comments at 5-6; Business Council for Sustainable Energy Initial Comments 2-3; Illinois Commission Initial Comments at 3-4; ISO-NE Initial Comments at 2; Michigan State Entities Initial Comments at 2-3; National Grid Initial Comments at 6-7; NESCOE Initial Comments at 9-10, 15-16; NextEra Reply Comments at 5, 25; Northwest and Intermountain Initial Comments at 5-6; Ørsted Initial Comments at 1-3; Pacific Northwest State Agencies Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 10-11; State Agencies Initial Comments at 16-17;

transmission planning inefficiencies.[122] For example, ACORE cites a recent National Renewable Energy Laboratory (NREL) report highlighting the need for new transmission to aid in achieving zero carbon goals.[123] NextEra opines that the passage of the Inflation Reduction Act of 2022 will increase the demand for renewables and drive corresponding demands on the transmission system.[124] Pacific Northwest State Agencies argue that reforms are critical to successfully achieving their respective state clean energy laws and policies and to ensuring that there is sufficient clean, safe, reliable, and affordable energy.[125] Michigan State Entities note that some states may pursue aggressive renewable energy portfolio standards, and others may have no such requirements, but these policy choices will inevitably affect the price and reliability of energy for all

Vermont Electric and Vermont Transco Initial Comments at 2; Western State Representatives Initial Comments at 3.

[122] *See, e.g.*, AEE Reply Comments at 3-4; California Democratic Representatives Supplemental Comments at 1-2; US Senators Supplemental Comments at 1 (citing to National Academies of Sciences, Engineering, and Medicine, *Accelerating Decarbonization in the United States: Technology, Policy, and Societal Dimensions* (2023)); Maryland Energy Admin Initial Comments at 1; North Carolina Commission and Staff Initial Comments at 2, 4; PJM States Initial Comments at 1; SREA Reply Comments at 4.

[123] ACORE Reply Comments at 1 (citing Paul Denholm, et al., NREL, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (Sept. 2022), https://www.nrel.gov/docs/fy22osti/81644.pdf).

[124] NextEra Reply Comments at 5, 25.

[125] Pacific Northwest State Agencies at 1.

customers across the states in question and that not planning for that reality imposes costs on unwilling customers.[126]

63. PacifiCorp and NV Energy similarly assert that the need for reform in the West is driven by the diverse policy priorities in its six-state transmission system, and they note that decisions are subject to state oversight and the participation of disparately situated transmission providers without inclination or authority to accept any cost allocation.[127] National Grid asserts that ISO New England's (ISO-NE) 2050 Transmission Study demonstrates a direct connection between state laws and requirements to meet clean energy goals and the need for new and expanded transmission facilities.[128] Indicated PJM TOs add that maintaining a reliable and resilient transmission system requires forward-looking assessments informed by evolving public policy, changing generation mix and demand patterns, and stakeholder input.[129]

64. Maryland Energy Administration contends that Maryland has experienced unfair and costly consequences of inadequate consultation with state authorities in regional transmission planning processes.[130] AEE argues that if current transmission planning

[126] Michigan State Entities Initial Comments at 2-3.

[127] PacifiCorp and NV Energy Initial Comments at 10-11.

[128] National Grid Initial Comments at 6-7 (citing the then-preliminary findings from the ISO-NE 2050 Transmission Study).

[129] Indicated PJM TOs Initial Comments at 1.

[130] Maryland Energy Administration Initial Comments at 1 (citing Maryland Energy Administration ANOPR Initial Comments at 2).

processes fail to incorporate factors such as state laws, corporate targets, and retail demand, then transmission needs will be unmet, risking unjust, unreasonable, and unduly discriminatory or preferential rates.[131]

65. Many commenters argue that, based on the record, the Commission has an obligation under the FPA to take action to ensure that transmission planning and cost allocation results in rates that are just and reasonable and not unduly discriminatory.[132] ACEG states that the Commission's broad authority to remedy unduly discriminatory behavior pursuant to FPA section 206 applies to transmission planning and cost allocation, as the U.S. Court of Appeals for the District of Columbia Circuit held in *South Carolina Public Service Authority v. FERC*.[133] PIOs contend that the Commission is required by the FPA to use its authority to address market abuses and undue discrimination that have led to unjust, unreasonable, and unduly discriminatory or preferential rates for consumers, who bear the costs of inefficiencies in the current transmission planning process.[134]

[131] AEE Reply Comments at 3-4.

[132] *See, e.g.*, ACEG Initial Comments at 11; Clean Energy Associations Initial Comments at 7-10; Grand Rapids NAACP Initial Comments at 17; Massachusetts Attorney General Initial Comments at 3-4; Pine Gate Initial Comments at 10-14; PIOs Initial Comments at 8.

[133] 762 F.3d at 57. *See also* ACEG Initial Comments at 13-14; Harvard ELI Initial Comments at 1-2; SEIA Initial Comments at 3.

[134] PIOs Initial Comments at 8.

66. Southeast PIOs assert that the NOPR adequately demonstrated that existing regional transmission planning processes have intrinsic flaws, making the integrated resource planning and request for proposal processes ill-equipped to efficiently address changes in the resource mix and demand.[135] Specifically, Southeast PIOs cite the following preliminary findings from the NOPR: (1) existing transmission planning processes utilize a limited planning horizon; (2) many transmission planning processes provide an inaccurate portrayal of the comparative benefits of different transmission facilities; and (3) rapid changes to the generation fleet and demand are creating increasingly urgent transmission needs.[136]

67. Southeast PIOs cite the finding in *South Carolina Public Service Authority v. FERC* that the threshold of substantial evidence could be met without "empirical evidence" as long as the Commission provides evidence based on "reasonable economic propositions."[137] Southeast PIOs also note that *South Carolina Public Service Authority v. FERC* upheld the Commission's findings in Order No. 1000, which were based on (1) a threat to just and reasonable rates from existing regional transmission planning and cost allocation practices, (2) significant changes in the industry driven by increases in

[135] Southeast PIOs Reply Comments at 4 (citing Duke Initial Comments at 6-9; SERTP Sponsors Initial Comments at 31-36; Southern Initial Comments at 36-40).

[136] *Id.* at 5-6 (citing NOPR, 179 FERC ¶ 61,028 at PP 45, 47, 49, 53).

[137] *Id.* at 6-7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65).

renewable energy resources, and (3) recent increases in transmission investment.[138] Moreover, Southeast PIOs note that findings need not be region-specific, as the "Commission may rely on generic or general findings of a systemic problem to support imposition of an industry-wide solution."[139]

68. ACEG similarly asserts that the Commission has shown the need for transmission planning reform based on findings that existing transmission planning requirements do not adequately identify transmission needs driven by changes in the resource mix and demand, and that failure to identify such needs causes customers to pay for less efficient or cost-effective transmission investments.[140] Relatedly, ACEG argues that pursuing region-specific solutions will lead to siloed and disjunctive transmission planning policies that will not solve the problems facing the nation's electric transmission system.[141]

69. Colorado Consumer Advocate and Joint Consumer Advocates aver that the Commission has a statutory duty under the FPA to reform current regional transmission planning processes because they lack transparency, coordination, and openness, and because they create opportunities for monopoly transmission developers to exert

[138] *Id.* at 6-7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65-66).

[139] *Id.* at 7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67).

[140] ACEG Reply Comments at 7-8 (citing Alabama Commission Initial Comments at 2-3; Duke Initial Comments at 6-9; Idaho Power Initial Comments at 2-3; NRECA Initial Comments at 11; North Carolina Commission and Staff Initial Comments at 14; Pacific Northwest Utilities Initial Comments at 9-10; Utah Commission Initial Comments at 9-12).

[141] *Id.* at 17.

dominant influence and promote their own economic self-interest at customers' and other stakeholders' expense.[142] According to New Jersey Commission, current transmission planning processes are inefficient and unnecessarily burden ratepayers with excessive costs without providing additional benefits. New Jersey Commission contends that those processes are therefore per se unjust and unreasonable, and that the Commission thus has FPA section 206 authority to require that transmission providers employ practices like long-term, holistic, multi-driver transmission planning.[143]

70. Similarly, Harvard ELI states that deficient transmission planning threatens the justness and reasonableness of transmission rates, and therefore the Commission has legal authority and jurisdiction to order changes to transmission planning to remedy that deficiency.[144] Harvard ELI further asserts that the Commission must remedy undue discrimination due to incumbent transmission owners' unduly discriminatory influence in regional transmission planning.[145] Massachusetts Attorney General also argues that the Commission's proposed reforms are necessary to fulfill the Commission's statutory obligation to ensure that transmission rates are just and reasonable.[146]

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[142] Colorado Consumer Advocate Initial Comments at 21-23; Joint Consumer Advocates Initial Comments at 18-20.

[143] New Jersey Commission Initial Comments at 3-4.

[144] Harvard ELI Initial Comments at 1-2 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41; Order No.1000-A, 139 FERC ¶ 61,132 at PP 56-75).

[145] *Id.* at 3.

[146] Massachusetts Attorney General Initial Comments at 3-6.

71. Some commenters argue that there is insufficient evidence for the Commission to find that existing jurisdictional rates are unjust, unreasonable, and unduly discriminatory or preferential.[147] For example, while Idaho Commission recognizes that there are deficiencies in existing transmission planning and cost allocation processes, Idaho Commission disagrees with the NOPR's claim that their failure to identify and plan for transmission needs driven by changes in the resource mix and demand is resulting in unjust, unreasonable, and unduly discriminatory or preferential Commission-jurisdictional rates.[148] Mississippi Commission also disagrees that the lack of long-term regional transmission planning will result in unjust, unreasonable, and unduly discriminatory or preferential rates.[149] ELCON questions a finding of unjust, unreasonable, and unduly discriminatory or preferential rates, and it states that the NOPR's focus on Long-Term Regional Transmission Planning solely to address changes in resource mix and demand, if adopted, could fail to produce better outcomes for customers and may exceed the Commission's authority under the FPA.[150]

[147] *See, e.g.*, ELCON Initial Comments at 7; Idaho Commission Initial Comments at 2; Mississippi Commission Initial Comments at 2, 9; NRECA Initial Comments at 14-16; Undersigned States Reply Comments at 6-7.

[148] Idaho Commission Initial Comments at 2 (citing NOPR, 179 FERC ¶ 61,028 at P 34).

[149] Mississippi Commission Initial Comments at 2.

[150] ELCON Initial Comments at 7.

72. Louisiana Commission states that the Commission's finding that, absent reforms, transmission rates universally are not just and reasonable and are discriminatory is not based on individual analysis of each RTO or region, is not supported, and should be retracted.[151] Mississippi Commission also states that the Commission should, instead, initiate region-specific investigations pursuant to FPA section 206.[152] Southern argues that the Commission has failed to satisfy the first prong of its FPA section 206 burden of proof, noting that the NOPR's preliminary conclusion, that existing regional transmission planning processes are not sufficient to address changes in the resource mix and demand, cannot reasonably be made of Southern or SERTP.[153]

73. Similarly, Industrial Customers argue that the Commission has not satisfied the first prong of FPA section 206, which requires the Commission to find, and provide substantial evidence supporting its finding, that existing rates are unjust, unreasonable, and unduly discriminatory or preferential.[154] Industrial Customers claim that demand growth should be the primary factor in identifying transmission needs, and that demand is growing more slowly than in previous periods. Industrial Customers add that, in contrast, investment in transmission is rising relative to demand, which is the opposite of the

[151] Louisiana Commission Reply Comments at 5-6.

[152] Mississippi Commission Reply Comments at 7-9.

[153] Southern Initial Comments at 40; Southern Reply Comments at 1-3.

[154] Industrial Customers Initial Comments at 6-7.

circumstances that prevailed in 2007 when the Commission issued Order No. 890.[155] According to Industrial Customers, changes in demand are not significant enough in historical terms to warrant major changes in transmission planning. Moreover, Industrial Customers state that changes in demand are unpredictable because technological changes are inherently difficult to forecast and the risks to consumers of making mistakes are too high. Industrial Customers argue that, if anything, the rapid growth of renewables indicates that current processes are already facilitating changes in the resource mix.[156] Similarly, NRG argues that long-term forecasts of important factors are often wrong, which has real-world impacts on customers.[157]

74. Further, Industrial Customers contend that the NOPR does not clearly define the term "changes in the resource mix and demand," despite using such changes as the justification for the proposals. Industrial Customers argue that transmission should only be planned in order to maintain reliability and should not be based on the demand for certain fuel sources or the fuel type of the generation fleet.[158] Industrial Customers argue that current transmission planning is based on known and measurable factors, and that

[155] *Id.* at 8-10.

[156] *Id.* at 10-11.

[157] NRG Initial Comments at 10-12 (noting, for example, that "[p]redictions for the future price of natural gas and thus the economics of gas generation in long-term forecasts have been notoriously inaccurate." (citing Lawrence Berkeley National Laboratory, *Comparison of AEO 2008 Natural Gas Price Forecast to NYMEX Futures Prices* (Jan. 2008)).

[158] Industrial Customers Initial Comments at 7-8.

any attempt to plan for potential future changes in the resource mix without determining precisely what these changes will be would result in the overbuilding of the system for generation that may not be built. Industrial Customers argue that this outcome would be unjust and unreasonable and would force transmission customers to pay for generation that is non-existent.[159]

75. Other commenters agree that the Commission lacks a specific record to support the need for reform.[160] For example, former Kansas Commission Chair Keen avers that there is no analytical or evidentiary basis in the NOPR for a complete and thorough overhaul or revision of transmission planning processes.[161]

76. Duke asserts that the NOPR does not provide robust and specific support as to how and why current regional transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment.[162] Duke asserts that the NOPR does not support the presumption that the absence of significant regional transmission investment is evidence of inefficient

[159] *Id.* at 15.

[160] *See, e.g.*, Alabama Commission Initial Comments at 4-5; Duke Initial Comments 6-9; Idaho Commission Initial Comments at 2; Industrial Customers Initial Comments at 1, 6-11, 15; Kansas Commission Chair Keen Initial Comments at 1-2; Nebraska Commission Initial Comments at 1-2; NRECA Initial Comments at 14-16; NRG Initial Comments at 3; Ohio Commission Federal Advocate Initial Comments at 5-6; Potomac Economics Initial Comments at 3-4; Southern Initial Comments at 40.

[161] Kansas Commission Chair Keen Initial Comments at 2.

[162] Duke Initial Comments at 6-7.

transmission planning.[163] Duke also asserts that, to ensure legal durability, the Commission should identify evidence that justifies a nationwide finding that current transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment and unjust, unreasonable, and unduly discriminatory or preferential rates.[164]

77. Undersigned States argue that the Commission does not have evidence in the record that current rates are unjust, unreasonable, or unduly discriminatory or preferential, which FPA section 206 requires.[165] Undersigned States argue that, contrary to the preliminary findings in the NOPR, the Southeast has developed significant and sufficient transmission infrastructure and renewable energy from 2015-2020. Undersigned States further argue that the Commission is supposed to enhance reliability, and that, because renewables are intermittent and inherently less reliable, forcing ratepayers to subsidize their use through financing the construction of additional transmission infrastructure is not consistent with the Commission's mission.

[163] *Id.* at 7-8.

[164] *Id.* at 9 (citing *Emera Me. v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017)).

[165] Undersigned States Reply Comments at 6-7. The Undersigned States that submitted reply comments include the States of Texas, Utah, Alabama, Alaska, Arkansas, Florida, Georgia, Kansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, Ohio, Oklahoma, South Carolina, and West Virginia. *Id.* at 1. The Undersigned States that submitted initial comments include the States of Utah, Alaska, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Texas, West Virginia, and Wyoming. Undersigned States Initial Comments at 5-6.

Undersigned States also argue that the Commission has not justified replacing existing transmission planning processes with a new approach, so the NOPR is arbitrary and capricious.[166] Further, Undersigned States argue that the Commission has not offered a detailed justification for countering prior precedent in Order No. 1000 that "the regional transmission planning process is not the vehicle by which integrated resource planning is conducted."[167]

78. Some commenters assert that the intention of the NOPR is to improperly favor certain energy resources.[168] Consumer Organizations argue that solutions that allow for an equitable transition and make space for advancing technology and smaller energy systems are preferrable to a rushed plan that favors certain resources, such as wind, solar, and battery storage, that have already proven to be inadequate.[169] ELCON adds that Congress did not give the Commission express authority to balance the FPA's just and reasonable rates requirement with the policy goal of connecting renewable resources to the transmission system.[170] SERTP Sponsors argue that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and

[166] Undersigned States Reply Comments at 6-8.

[167] *Id.* at 8 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

[168] *See, e.g.*, Consumers Organizations Initial Comments at 1-3; ELCON Initial Comments at 9-10.

[169] Consumers Organizations Initial Comments at 1-3.

[170] ELCON Initial Comments at 9-10 (citing 16 U.S.C. 824q(b)(4)).

thereby effect particular, substantive transmission outcomes; rather, SERTP Sponsors continue, Congress has expressly and unequivocally reserved generation authority to the states.[171] Louisiana Commission argues that the FPA does not confer on the Commission authority to engage in wide-scale public policymaking by enacting sweeping energy policy changes with far-reaching, nationwide effects.[172]

79. Ohio Commission Federal Advocate states that the NOPR may be intended "to establish policies designed to encourage the massive transmission build-out that will doubtless be required to transition to an aspirational renewable future" and "to achieve narrow environmental policy objectives, not to address legitimate requirements under the Federal Power Act like ensuring just and reasonable rates or reliability."[173] Former Kansas Commission Chair Keen claims that the NOPR encourages an extensive and expensive transmission build-out without considering the impact on state-jurisdictional generation mixes. He also claims that some of the NOPR proposals impose an accelerated pace for the transition from dispatchable to renewable resources, which could hasten the premature retirement of dispatchable generation and compromise regional and state power reliability. He also expresses concern that the NOPR proposals would force

[171] SERTP Sponsors Initial Comments at 18.

[172] Louisiana Commission Initial Comments at 6 (citing *West Virginia v. EPA*, 597 U.S. 697 (2022)).

[173] Ohio Commission Federal Advocate Initial Comments at 4-5 (citing NOPR, 179 FERC ¶ 61,028, Danly, Comm'r, dissenting, at PP 2-3).

ratepayers in some states to pay for neighboring states' transmission projects to advance public policy goals that they do not share.[174]

80. Some commenters challenge aspects of the need for reform. For example, Nebraska Commission believes that the established structures in RTO/ISO regions are generally working and that many aspects of the NOPR are thus unnecessary there.[175] Potomac Economics disagrees with some of the Commission's arguments for requiring Long-Term Regional Transmission Planning, contending that the Commission's proposals are based on anticipated future generation and other speculative factors and seem to be incorrectly premised on a presumption that congestion should not exist or may limit investment in economic generation. Potomac Economics states that investment should occur only to the extent that the savings of reducing congestion are larger than the investment costs. According to Potomac Economics, congestion that is caused by generators' siting decisions should be borne by the generation developers, as it will incent them to propose the lowest-cost projects taking transmission costs into account. Potomac Economics argues that, if transmission is expanded preemptively to facilitate generation investment in a particular location, such costs are equivalent to subsidies for the developer.[176]

[174] Kansas Commission Chair Keen Initial Comments at 3.

[175] Nebraska Commission Initial Comments at 1-2.

[176] Potomac Economics Initial Comments at 3-4.

81. Mississippi Commission disagrees that too much expansion of high-voltage transmission has occurred through the generator interconnection process instead of through regional transmission planning.[177] Similarly, North Carolina Commission and Staff disagree with the Commission's conclusion that the growth in interconnection-related network upgrades demonstrates a failure of regional transmission planning as it relates to North Carolina.[178] Southern adds that, contrary to statements in the NOPR, it is not significantly expanding its transmission system through the generator interconnection process.[179]

82. Alabama Commission asserts that Alabama has a resource planning process that accounts for needed transmission buildout to maintain reliable service, and thus, Alabama Power plans its transmission system proactively both to maintain deliveries from existing resources and to accommodate Alabama Commission-certified generation additions. Alabama Commission claims that the SERTP process builds on the integrated resource planning efforts of its sponsor states, ensuring that there are no regional transmission solutions that are more efficient or cost-effective than solutions identified through the underlying state-jurisdictional processes.[180]

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[177] Mississippi Commission Initial Comments at 9.

[178] North Carolina Commission and Staff Initial Comments at 5.

[179] Southern Initial Comments at 38-40.

[180] Alabama Commission Initial Comments at 4.

83. Duke argues that, for certain transmission providers, the local transmission planning process may more effectively meet transmission needs, especially when combined with state-regulated integrated resource planning and a bottom-up regional transmission planning process. Duke contends that a regional transmission facility may not fully address local transmission needs such that a local transmission facility would still be needed, and thus, the regional transmission facility is not necessarily more efficient or cost-effective than the local transmission facility.[181]

84. NRECA states that certain of its members in RTOs/ISOs believe that regional transmission planning is working well to meet long-term needs (e.g., those in MISO) and that the NOPR proposals would burden transmission providers' limited resources. NRECA states that other NRECA members in RTOs/ISOs believe that existing RTO/ISO transmission planning processes contain discrete deficiencies that the NOPR proposals will not remedy. According to NRECA, these electric cooperatives believe that some incumbent investor-owned transmission owners develop local transmission projects without transparency concerning need or costs, leading to disparities in transmission rates across RTO/ISO transmission zones, and that incumbent transmission owners control the transmission planning process such that no regional transmission planning occurs. NRECA states that, in these cooperatives' view, the criteria to determine the eligibility of

[181] Duke Initial Comments at 7-9.

a regional transmission project is the barrier, and that requiring Long-Term Regional Transmission Planning, by itself, will not solve the problem.[182]

### C. Commission Determination

85. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements is causing transmission providers to fail to adequately anticipate and plan for future system conditions. It causes transmission providers to fail to appropriately evaluate the benefits of transmission infrastructure, and results in piecemeal transmission expansion to address relatively near-term transmission needs. We find that this status quo causes transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than necessary or appropriate to meet their transmission needs and forgoing benefits that outweigh their costs, which results in less efficient or cost-effective transmission investments. As explained below, we find that these deficiencies render Commission-

[182] NRECA Initial Comments at 14-16.

jurisdictional regional transmission planning and cost allocation processes unjust, unreasonable, and unduly discriminatory or preferential.

86. The Commission has authority under FPA section 206 to issue this final rule. Specifically, FPA section 206 "instructs the Commission to remedy 'any . . . practice' that 'affect[s]' a rate for interstate electricity service 'demanded' or 'charged' by 'any public utility' if such practice is 'unjust, unreasonable, unduly discriminatory or preferential.'"[183] As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction.[184] As the Court explained in *South Carolina Public Service Authority v. FERC*, transmission providers use those processes to "determine which transmission facilities will more efficiently or cost-effectively meet" transmission needs, the development of which directly impacts the rates, terms, and conditions of Commission-jurisdictional service.[185] In particular, because these processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates, we find that they directly affect those rates.[186] In addition, as

[183] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55 (quoting 16 U.S.C. 824e(a)).

[184] *Id.* at 55-59, 84 (affirming the Commission's authority to regulate transmission planning and cost allocation as practices affecting rates); *see also* Order No. 1000-A, 139 FERC ¶ 61,132 at P 577 (holding that "requirements regarding transmission planning and cost allocation . . . are practices affecting rates.").

[185] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 112, 116); *see also Emera Me. v. FERC*, 854 F.3d at 674.

[186] That is true even if regional transmission planning and cost allocation processes do not result in the development, siting, and construction of every regional transmission

discussed below, such transmission facilities contribute to the development of a more robust transmission system, supporting continuity of service in the face of growing reliability challenges and providing wholesale electric customers greater access to lower-cost generation supplied by a wider range of resources. Accordingly, regional transmission planning and cost allocation processes, as well as "the rules and practices that determine how those [processes] operate,"[187] have a direct effect on the rates that customers pay for *both* the transmission and sale of electric energy in interstate commerce.[188] The Commission may act pursuant to FPA section 206 if the Commission first establishes, through substantial evidence,[189] that the existing practices are unjust, unreasonable, or unduly discriminatory or preferential and, second, establishes that the replacement practices are just and reasonable.[190]

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facility that transmission providers select to more efficiently or cost-effectively meet transmission needs. *See, e.g.*, *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 485 (D.C. Cir. 2009) (holding that "even if all [that] the I[nstalled] C[apacity] R[equirement] did was help to find the right [capacity] price," rather than result in the construction or procurement of any new capacity, "it would still amount to a 'practice . . . affecting' rates." (citing 16 U.S.C. 824e(a) (omission in original))).

[187] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 279 (2016) (*EPSA*).

[188] 16 U.S.C. 824e(a).

[189] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 54 ("The Commission's factual findings are conclusive if supported by substantial evidence."). Courts have held that substantial evidence in this context does not necessarily require the Commission to provide *empirical* evidence for every proposition. Rather, FPA section 206 empowers the Commission to address a mere *threat* of unjust and unreasonable rates. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64-65, 85.

[190] 16 U.S.C. 824e(a); *see also EPSA*, 577 U.S. at 277 (affirming the Commission "has the authority—and indeed, the duty—to ensure that rules or practices 'affecting'

87. With regard to the first showing under FPA section 206, we find that, while Order No. 890 requires transmission providers to satisfy certain principles in their local transmission planning processes and Order No. 1000 requires transmission providers to participate in regional transmission planning and cost allocation processes that satisfy the requirements set forth therein, these existing transmission planning and cost allocation requirements do not result in regional transmission planning that is conducted on a sufficiently long-term, forward-looking, and comprehensive basis to plan for Long-Term Transmission Needs. As a result, we find that transmission providers are often not identifying, evaluating, or selecting more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs. This gap in existing regional transmission planning processes results in piecemeal, inefficient, and less cost-effective transmission planning that imposes real costs on customers, who pay Commission-jurisdictional transmission rates for less efficient or cost-effective transmission facilities and do not realize the benefits that would result from long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes that identify, evaluate, and select more efficient or cost-effective transmission solutions to Long-Term Transmission Needs.

88. We find that these deficiencies in the Commission's existing transmission planning and cost allocation requirements render those requirements unjust, unreasonable, and unduly discriminatory or preferential in violation of FPA section 206.

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wholesale rates are just and reasonable").

89. We also find that the Commission's existing transmission planning and cost allocation requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates. Given these findings, we are now requiring, pursuant to FPA section 206, that transmission providers engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs. We find that these reforms will facilitate a process by which transmission providers can better identify, evaluate, and select more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs, which will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

### 1. The Transmission Investment Landscape Today

90. As the Commission explained in the NOPR, a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity.[191] Due to continuing changes in the industry, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable,[192]

[191] NOPR, 179 FERC ¶ 61,028 at P 28 (citing 16 U.S.C. 824, 824d, 824e); *see also* US DOE ANOPR Initial Comments at 2 (stating that "strengthening and expanding existing transmission infrastructure, particularly the development of regional and inter-regional transmission projects, is key to continued access to reliable, resilient, lower-cost, and clean electricity for all").

[192] *See, e.g.*, MISO ANOPR Initial Comments at 40; Testimony of James B. Robb Before the U.S. Senate Energy and Natural Resources Committee, *Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events*, at 8-9 (Mar. 11, 2021), https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11 (testifying that more transmission infrastructure is required to ensure the reliability and resilience of the bulk

affordable, and economically efficient fashion. Such investments support enhanced reliability, as larger, more integrated transmission systems result in a diversity of supply and demand conditions and a certain degree of redundancy that allows the system to better withstand failures during extreme events.[193] Proactive, forward-looking transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints, as well as to evaluate potential transmission solutions, well in advance of these issues affecting the transmission system,[194] which can facilitate the selection of more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.

91. In addition, transmission infrastructure can unlock the forces of competition, changing who can sell to whom, eliminating barriers to entry, and mitigating market

power system in light of changing conditions).

[193] ACORE ANOPR Initial Comments Ex. 4, Grid Strategies July 2021 Extreme Weather Report; Mark Chupka & Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience* (May 2018), https://wiresgroup.com/wp-content/uploads/2020/06/2018-05-09-Brattle-Group-Recognizing-the-Role-of-Transmission-in-Electric-System-Resilience-.pdf; NERC ANOPR Initial Comments at 17-18; US DOE ANOPR Initial Comments at 18.

[194] MISO's Multi-Value Project (MVP) regional transmission planning process, for example, eliminated the need for approximately $300 million in reliability transmission facilities, resolving reliability violations and mitigating system instability conditions, through a forward-looking approach. Midcontinent Independent System Operator, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, at 11, 33 (Sept. 2017) (MTEP2017 Review).

power.[195] Increased competition, in turn, can provide a host of benefits for customers, including cost-savings from greater access to low-cost power and a wider range of resources.[196] Transmission infrastructure can also serve as a form of insurance against future uncertainties because a more robust, integrated transmission system has the potential to provide consumers with the benefits of competition and enhanced reliability even if supply and demand fundamentals change over time.[197]

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[195] Policy Integrity ANOPR Initial Comments at 13 n.40 ("A new transmission project can enhance competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load." (citing Mohamed Awad et al., *The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Applications to Path 26*, at 3 (2006)); PIOs ANOPR Initial Comments Ex. A, Johannes Pfeifenberger et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, at 48-49 (Oct. 2021) (Brattle-Grid Strategies Oct. 2021 Report), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf ("Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade . . . ." (quoting F.A. Wolak, World Bank, *Managing Unilateral Market Power in Electricity*, Policy Research Working Paper No. 3691, at 8 (2005))).

[196] *See, e.g.*, PJM Interconnection, L.L.C., *PJM Value Proposition*, at 1-2 (2019), https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx (PJM's planning of resource adequacy over a large region is estimated to result in savings of $1.2-1.8 billion.); Midcontinent Independent System Operator, *MISO Value Proposition* (2020), https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/ (MISO estimated $517-572 million in savings from more efficient use of existing assets and $2.5-3.2 billion from reduced need for additional assets.); SPP Transmission Planning, Southwest Power Pool, *SPP's Value of Transmission: 2021 Report and Update* (Mar. 31, 2022) (SPP estimated $382.7 million in adjusted product costs savings in 2020 due to transmission investment.); *see also* ACEG Initial Comments at 3-4 ("The benefits generated by MISO's MVPs and SPP's Priority Projects exceeded the costs by 2.2 to 3.5 times and means that every dollar spent on transmission will enable access to generation that is $3 to $4 cheaper than would otherwise be available.").

[197] US DOE, *National Electric Transmission Congestion Study*, at 11 (Sept. 2015),

92. With that overview, we again begin with the key facts on the ground.[198] Since the issuance of Order No. 1000, transmission spending has continued to increase nationwide. A study by US DOE found that "annual investment [in transmission] first exceeded $5 billion per year in 2006 . . . and has increased consistently since that time. Annual investment [] doubled to more than $10 billion per year by 2010 and then [] doubled again by 2016. Annual investment has been between $18 billion and $22 billion annually since 2014."[199] A separate study, noted by the Commission in the NOPR, estimated that transmission developers in the United States invested $20 to $25 billion annually in transmission facilities from 2013 to 2020.[200] Unsurprisingly, in regions that saw a significant increase in transmission expenditures, transmission costs have also become an

https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf (stating transmission expansion can strengthen and increase the flexibility of the overall network and "create real options to use the transmission system in ways that were not originally envisioned"); Vikram S. Budhraja et al., *Improving Electricity Resource Planning Processes by Considering the Strategic Benefits of Transmission*, 22 ELEC. J. 54 (Mar. 2009) (high voltage transmission affords "mitigation of risks as a form of insurance against extreme events").

[198] NOPR, 179 FERC ¶ 61,028 at P 36.

[199] California Commission Reply Comments at 9 n.27 (quoting US DOE, *National Electric Transmission Congestion Study*, at 9-10 (Sept. 2020), https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf).

[200] NOPR, 179 FERC ¶ 61,028 at P 39 (citing Brattle-Grid Strategies Oct. 2021 Report at 2); Brattle Apr. 2019 Competition Report at 2-3 & fig.1.

increasing share of customers' overall electricity bills, underscoring the importance of ensuring that transmission investments are efficient and cost-effective.[201]

93. Furthermore, the record demonstrates that transmission investment is likely to substantially increase in coming years. A number of studies project significant and sustained transmission spending through at least 2050. For example, one projection cited by the US DOJ and FTC states that "high voltage transmission capacity must expand by 60 percent by 2030 at a capital cost of $330 billion, and must triple by 2050 at a capital cost of $2.2 trillion."[202] TAPS cites a separate study projecting $750 billion of new transmission investment between 2023 and 2050.[203] SoCal Edison "estimates that grid

[201] Resale Iowa Initial Comments at 3 ("[T]ransmission costs have comprised an increasing percentage of [] total wholesale electric costs [for Resale Iowa's members]. Currently, transmission and ancillary services constitute approximately 43% of such costs, as compared to 18.1% in 2009."); Industrial Customers Initial Comments at 5 (showing that transmission costs made up just 7% of the total PJM electricity bill in 2011 but 27% by 2020); Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 26-28 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf (ACEG Jan. 2021 Planning Report) (stating that the current approach to transmission planning "results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning"); *see also* California Municipal Utilities Initial Comments at 10 (projecting that between 2022 and 2040, total high and low-voltage transmission access charges will nearly double and noting that "[g]one are the days when transmission was a *de minimis* portion of the overall bill and increases had little impact on the end consumer"); Public Systems Initial Comments at 5 (noting that "New England's Regional Network Service transmission rate has grown *nine-fold*, from $15.60 per kW-year (in 2003) to $140.98 per kW-year (in 2021)").

[202] US DOJ and FTC Initial Comments at 3 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Princeton Univ., 108 (Oct. 2021), https://netzeroamerica.princeton.edu/the-report).

[203] TAPS Initial Comments at 46 & n.133 (citing Jürgen Weiss et al., The Brattle

investments of up to $75 billion, including transmission upgrades, will be required from 2030 to 2045 *in California alone* to integrate bulk renewable generation and storage and serve load growth associated with electrification."[204] And ISO-NE's recently-completed 2050 Transmission Study estimates that transmission investment in New England will range from $16 billion to $26 billion between 2024 and 2050, depending on the amount of load growth realized in the region.[205]

94. The growing need for new transmission infrastructure, particularly over a longer time horizon, is being driven by a number of factors. First, longer-term reliability needs are changing. The NOPR explained that transmission system operators are increasing their reliance on regional transmission facilities to ensure operational stability, particularly because of the growing frequency of extreme weather events and increasing share of variable resources entering the resource mix.[206] The comments submitted in response to the NOPR support that preliminary finding. The record shows that changing

Group, *The Coming Electrification of the North American Economy*, at iii (2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf)).

[204] SoCal Edison Initial Comments at 2 (citing Southern California Edison, *Pathway 2045: Update to the Clean Power and Electrification Pathway* (2019), https://download.newsroom.edison.com/create_memory_file/?f_id=5dc0be0b2cfac24b300fe4ca&content_verified=True) (emphasis added)).

[205] ISO-NE, *2050 Transmission Study*, at 55-56 (Feb. 12, 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

[206] NOPR, 179 FERC ¶ 61,028 at P 45.

reliability needs are driving a significant shift in demands placed on the transmission system,[207] and that because extreme weather events are occurring with greater frequency, transmission is increasingly critical to ensuring system reliability.[208] For example, Winter Storm Uri demonstrated that transmission infrastructure can make critical contributions to system reliability during extreme weather events,[209] as well as how

[207] ACEG Initial Comments at 5 (noting that weather-related power outages cost Americans $25-70 billion annually (citing Grid Strategies July 2021 Extreme Weather Report at 1)); *id.* at 52 (explaining that "[c]hanges to the transmission planning processes that would allow for certain transmission upgrades identified in the interconnection process to be addressed and ultimately constructed through the transmission planning process will only serve to increase the resiliency and reliability of the transmission system."); ACEG Reply Comments at 5-6 ("[R]eliability requires long term transmission planning that incorporates known and knowable information about the future resource mix."); NERC Initial Comments at 6 ("Transmission will be the key to support the resource transformation enabling delivery of energy from areas that have surplus energy to areas which are deficient. The frequency of such occurrences are increasing as extreme weather conditions resulting from climate change impact the fuel sources for variable energy resources. Regional transmission planning can ensure that sufficient amounts of transmission capacity will be needed to address these more frequent extreme weather conditions.").

[208] *See* DC and Maryland Offices of People's Counsel Reply Comments at 2 (noting that new transmission development has benefits including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather); Indicated PJM TOs Initial Comments at 1 (explaining that maintaining a "reliable and resilient" transmission system requires holistic planning); NESCOE Initial Comments at 32-33 ("ISO-NE explains that energy-security risks in New England are well documented, highlighting the importance of conducting comprehensive energy security assessments covering a wide range of operating conditions, including low-probability, high-impact reliability risks (tail risks) related to extreme weather" (internal quotations omitted)); NYISO Initial Comments at 16 (expressing a desire to engage in actionable scenario planning to plan for future reliability challenges that may arise due to extreme weather, including the loss of all generation connected to a pipeline or other fuel sources, loss of an entire transmission line, and impacts from weather events like hurricanes or wildfires).

[209] ACEG Initial Comments at 22 n.63 (During Winter Storm Uri, "[a]n additional

transmission constraints can prevent operational generation resources from being able to serve load during tight supply conditions.[210] Consistent with experience from Winter Storm Uri, US DOE's Lawrence Berkeley National Laboratory provides further evidence of the significant value of transmission during unanticipated events, with research suggesting that 50% of the value created by alleviating transmission system congestion occurs during only 5% of the hours during which the transmission system is used.[211] Thus, transmission investment is likely to be more critical, and produce more reliability benefits, for customers as extreme weather and other system contingencies become more

1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion and kept power flowing to hundreds of thousands of Texans." (citing Grid Strategies July 2021 Extreme Weather Report at 1-3, 12)); Grid Strategies July 2021 Extreme Weather Report at 7-8 ("The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during [Winter Storm Uri]. . . . In contrast to the 13,000 MW MISO was importing during the peak of [the] event, ERCOT was only able to import about 800 MW of power throughout the event."); NARUC Initial Comments at 67 n.192 (During Winter Storm Uri, SPP's "'relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.'" (quoting Southwest Power Pool, *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations*, at 9 (July 2021), https://spp.org/documents/65037/comprehensive%20review%20of%20spp%27s%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf (brackets omitted))).

[210] *See* Advanced Energy Buyers Initial Comments at 3.

[211] ACORE Initial Comments at 10-11 (citing LBNL Aug. 2022 Transmission Value Study at 33); US DOE Initial Comments at 5-6 & n.13.

frequent.[212] For some communities who can be more susceptible to the impacts of extreme weather, like communities of color and low-income communities, transmission investment has the potential to be even more critical.[213] Conversely, failure to adequately plan the transmission system to meet such changing reliability needs will forgo many of those potential benefits, jeopardize system reliability, and force customers to pay for transmission facilities that may not efficiently or cost-effectively address urgent reliability needs.

95. Second, demand is changing. After many years of flat or minimal load growth in regions across the country, demand, on both a national and a regional basis, is projected to significantly increase in the coming decades, and it will require an increasingly robust transmission system to reliably serve this load growth. As stated in the NOPR, changes in electric demand and associated load profiles are occurring as load-serving entities work to meet increasing needs due to electrification trends, as well as new large loads associated with evolving industrial and commercial needs, such as growth in data centers.[214] The comments submitted in this record demonstrate that, in regions across the

[212] ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33; *see also* Clean Energy Associations Initial Comments at 5.

[213] *See, e.g.*, WE ACT Initial Comments at 1-2 & n.3 (citing Jeff Turrentine, NRDC, *A Roadmap for Frontline Communities* (Dec. 2019)); *see also* Grand Rapids NAACP Initial Comments at 8 n.20 ("[P]ower outages uniquely burden low-income communities of color 'given that they are unable to 'bounce back' as quickly from events that damage food and medicine supplies'" (citing Shalanda Baker et al., *The Energy Justice Workbook 20* (2019), https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf)).

[214] NOPR, 179 FERC ¶ 61,028 at PP 45, 51. The continuation and, in some

country, customers are electrifying everything from household appliances to vehicles.[215] Comments also substantiate the fact that, in many regions, large loads associated with new and emerging industrial needs, like data centers, are driving rapid load growth.[216]

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instances, acceleration of these trends identified in the ANOPR and NOPR counters certain commenters' concerns that changes in demand are inherently unpredictable or that existing regional transmission planning processes are adequately identifying and addressing transmission needs. *Compare infra* notes 15-8 and accompanying discussion, *with* Potomac Economics Initial Comments at 3-4 (arguing that Long-Term Regional Transmission Planning that requires speculating about future uncertainty is not advisable), *and* Industrial Customers Initial Comments at 10-11 (arguing that changes in demand are unpredictable).

[215] AEE Initial Comments at 1, 14 (noting that, as of 2022, "[n]ine states have also taken steps directly to promote electrification of transportation and buildings. Individuals and governments are also adopting electric vehicles; for example, light-duty electric vehicle sales have increased from 10,092 vehicles in 2011 to 459,426 vehicles in 2021, over a 4400% increase."); Renewable Northwest Initial Comments at 20 (explaining that heat pumps installed as part of building electrification could add large new weather-dependent loads, estimated at 20,000 to 40,000 MW of incremental peak capacity by 2050 across the Pacific Northwest); *see also* AMP Initial Comments at 4; ISO-NE, *Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results*, at 190-94 (Nov. 2023) (providing sensitivity that included 15% and 10% increases in peak load and average hourly loads, respectively, driven by heating and vehicle electrification); U.S. Energy Info. Admin. (EIA), *Incentives and Lower Costs Drive Electric Vehicle Adoption in Our Annual Energy Outlook*, (May 15, 2023) (noting that, per 2023 Annual Energy Outlook Projections, electric vehicles will account for between 13% and 29% of new light-duty vehicle sales in the United States, and between 11% and 26% of then on-road light duty vehicle stocks, by 2050).

[216] *See, e.g.*, Transmission Dependent Utilities Initial Comments at 4-5 ("For example, the PJM Interconnection, L.L.C. Transmission Expansion Advisory Committee recently posted that Dominion Energy Virginia will need over $603 million in transmission upgrades through 2025—just three years from now—to accommodate significant data center load growth in Northern Virginia." (citing PJM Transmission Advisory Committee, *Reliability Analysis Update*, at 3, 5 (Aug. 9, 2022))). These trends are continuing and even accelerating. *See* PJM Interconnection, L.L.C., *PJM Load Forecast Report*, at 1 (Jan. 2024), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx (noting upward adjustments in 2024 load

Estimates quantifying the magnitude of this shift show that it is significant, with nationwide demand for electricity projected to increase by 5% to 15% (200 to 600 TWh) by 2030.[217] That trend is projected not just to continue but to accelerate, with nationwide demand for electricity projected to increase by 25% to 85% (1,100 to 3,700 TWh) by 2050.[218] Industrial customers in many regions are driving much of this increase; industry executives have reported that electrification initiatives, through which many of the nation's largest companies plan to electrify their manufacturing processes, transportation,

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forecasts for certain zones to account for large, unanticipated load growth driven by data centers, a chip processing plant, and port electrification, among other factors); *id.* at 78 (projecting increase from 2,333 GWh in 2024 to 130,489 GWh in 2039 due to plug-in electric vehicles); *id.* at 30 (showing 1.0% higher load growth projection for 2024, 6% higher load growth projection for 2029, and 10.4% higher load growth projection for 2034, as compared to 2023 Load Forecast Report).

[217] National Grid Initial Comments at 8 (citing Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy* (Mar. 2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf).

[218] *Id.*; *see also* John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over*, at 3 (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf ("Over [2023], grid planners nearly doubled the 5-year load growth forecast. The nationwide forecast of electricity demand shot up from 2.6% to 4.7% growth over the next five years, as reflected in 2023 FERC [Form 714] filings. Grid planners forecast peak demand growth of 38 gigawatts (GW) through 2028."); N. Amer. Elec. Reliability Corp., *2023 Long-Term Reliability Assessment*, at 33 (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf ("Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022* [*Long-Term Reliability Assessment*], reversing a decades-long trend of falling or flat growth rates.").

and heating operations, are well underway or soon to begin.[219] Importantly, the record shows that these increases in aggregate demand for electricity will have significant consequences for the transmission system. To serve more load, the capacity of the already-oversubscribed transmission system will need to increase.[220] Moreover, load growth driven primarily by electrification can create a load profile that has a higher load factor and that is thus more challenging to serve.[221]

[219] Renewable Northwest Initial Comments at 20 ("A recent study done by Deloitte showed that 70 percent of executives in industrial manufacturing industries have plans for the electrification of industrial processes, and 50 percent of the executives who responded have goals to electrify vehicle fleets and space and water heating within their companies by 2030." (citing Stanley Porter et al., Deloitte, *Electrification in Industrials* (Aug. 2020), https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/electrification-in-industrials.html)).

[220] *See, e.g.*, National Grid Initial Comments at 6 (discussing preliminary findings of the ISO-NE 2050 Transmission Study, which show "significant new transmission will be needed to reliably serve" increased future loads assumed in the study (citing ISO-NE, *2050 Transmission Study* (2023), https://www.iso-ne.com/static-assets/documents/2023/08/2050_study_ma_cetwg_2023_aug_final.pdf)); Northwest and Intermountain Initial Comments at 5 n.12 ("For example, Bonneville Power Administration ('BPA') owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA's 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests." (citing BPA, *TSR Study and Expansion Process*, at 12 (Dec. 2021), https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf.)).

[221] MISO Initial Comments at 54 ("In addition, a return to load growth driven primarily by the electrification of transportation, space heating and water heating is creating a load profile that has a higher load factor and is more challenging to serve."). Load factor refers to "[t]he ratio of the average load to peak load during a specified time interval." U.S. Energy Info. Admin. (EIA), *Glossary* (last visited Mar. 2024), https://www.eia.gov/tools/glossary/index.php?id=L.

96. Third, supply is changing. As the NOPR explained, federal, state, and local policies are incentivizing various forms of generation resources and other technologies,[222] resulting in changes to the nation's resource mix. The comments in this record show that these policies are widespread and now span many regions of the country. States and cities in the Northeast,[223] Mid-Atlantic,[224] Midwest,[225] West,[226] and Southeast[227] have

[222] NOPR, 179 FERC ¶ 61,028 at P 45.

[223] National Grid Initial Comments at 6-7 (explaining how all six states in New England have renewable energy standards and how ISO-NE's 2050 Transmission Study demonstrates the demands that meeting those standards will place on New England's transmission system); *id.* at 7 (explaining how the Climate Leadership and Community Protection Act enacted in New York State requires 70% renewable generation by 2030, zero-emissions by 2040, and 85% economy-wide emissions reductions by 2050, and that transmission infrastructure will be critical in meeting those goals); NESCOE Initial Comments at 15 ("Achieving a decarbonized system is required by laws and mandates in Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.").

[224] DC and MD Offices of People's Counsel Initial Comments at 18 (noting that "both Maryland and the District have adopted ambitious jurisdiction-wide decarbonization policies applicable to the [electric distribution companies] regulated by their respective public service commissions.").

[225] Illinois Commission Initial Comments at 5 (explaining that "[i]n Illinois, the Climate and Equitable Jobs Act of 2021 . . . will affect the future resource mix and demand and lead to decarbonization and electrification. For example, [it] requires Illinois to completely transition to clean energy by 2050 and facilitates electrification through the promotion of electric vehicles.").

[226] Renewable Northwest Initial Comments at 6 (explaining that, "[c]urrently, 80 percent of NorthernGrid's load is subject to state clean energy laws, and by 2040 NorthernGrid will have 65 percent carbon-free energy."); *id.* at 21 (explaining that Washington state's "SB 5974 sets a goal of all vehicles sold in 2030 and beyond to be [electric vehicles], with that goal becoming a mandate in 2035[.]").

[227] SREA Initial Comments at 25 (noting that North Carolina has adopted Renewable Energy and Energy Efficiency Portfolio Standards and enacted the North Carolina Carbon Plan).

adopted binding state laws requiring emissions reductions. Moreover, with the passage of the Inflation Reduction Act in 2022, Congress has enacted legislation that will further spur investment nationwide in renewable and non-emitting resources.[228]

97. Customers are also driving changes in the resource mix. In addition to increasing their aggregate demand for electricity, the NOPR explained that customers, including major corporations, in many regions are increasingly demanding that load be served by renewable or non-emitting resources.[229] Substantial evidence in the record supports the existence of this trend. Since 2014, for example, "commercial and industrial customers have contracted for more than 52 GW of clean energy[.]"[230] Furthermore, this trend is

[228] ACORE Initial Comments at 1-2 & n.2 (projecting that "annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025-2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter." (citing REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, at 15 (2022), https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-12.pdf)); CARE Coalition Initial Comments at 17 ("Analysis suggests that the [Inflation Reduction Act] could more than triple clean energy production in the U.S. and lead to $600 billion in capital investment in clean energy infrastructure." (citing American Clean Power Ass'n, *It's a Big Deal for Job Growth and for a Clean Energy Future* (2022), https://cleanpower.org/blog/its-a-big-deal-for-job-growth-and-for-a-clean-energy-future)); Evergreen Action Initial Comments at 3-4 (discussing model showing that clean energy could comprise up to 81% of all U.S. generation as a result of increased incentives in the Inflation Reduction Act (citing John Larsen et al., Rhodium Group, *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act* (2022), https://rhg.com/research/climate-clean-energy-inflation-reduction-act)); NextEra Reply Comments at 5 ("The signing of the Inflation Reduction Act of 2022 . . . will only increase the demand for renewables in the coming years and accelerate corresponding demands on the transmission system.").

[229] NOPR, 179 FERC ¶ 61,028 at P 45.

[230] Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers

accelerating. In 2021 alone, energy customers voluntarily contracted for "11.06 GW of clean energy."[231] The record demonstrates that, going forward, this shift is projected to continue, as forecasts show that Fortune 1000 companies will have up to 85 GW of new demand for renewable energy to meet their public sustainability commitments for 2030.[232] As also noted in the NOPR, utilities in many regions have made commitments to procure most or all of their electricity from renewable or non-emitting resources. For example, Exelon,[233] Dominion,[234] AEP,[235] and Southern[236] have all committed to achieve

Alliance, *State of the Market 2022*, https://cebuyers.org/state-of-the-market/).

[231] Clean Energy Buyers Initial Comments at 7.

[232] Clean Energy Buyers Initial Comments at 7 n.13 (citing Clean Energy Buyers ANOPR Initial Comments at 21-22).

[233] Exelon Initial Comments at 2 ("Exelon has established ambitious targets and aims to be a leader in clean energy by continuing to reduce its own greenhouse gas emissions, including reducing operations-driven emissions 50 percent by 2030, relative to a 2015 baseline, and achieving net-zero operations by 2050." (citing Calvin Butler, Exelon Corporation, *We're on the Path to Clean* (Apr. 2021), https://www.exeloncorp.com/grid/were-on-the-path-to-clean)).

[234] Dominion Initial Comments at 3-4 ("Dominion Energy has committed to achieve net zero greenhouse gas emissions by 2050 and is investing in clean energy resources such as solar and wind.").

[235] AEP Initial Comments at 4 n.12 ("AEP's goal is to reduce carbon emissions from directly owned generation by 80% by 2030 compared to 2000 levels and to achieve net-zero emissions by 2050." (citing AEP, *2022 Corporate Sustainability Report*, at 48 (2022), https://www.aep.com/news/releases/read/8520/AEP-Releases-2022-Corporate-Sustainability-Report)).

[236] Southern Initial Comments at 14 ("By 2019, Southern Companies had already achieved a 44% reduction in greenhouse gas emissions in pursuit of its goals of a 50% reduction by 2030 and net zero by 2050.").

net-zero emissions by 2050, and each has set an interim goal to significantly reduce emissions by 2030. And, although utility commitments vary by utility and by region, the record shows that many utilities have announced some future emissions target.[237]

98. Furthermore, as noted in the NOPR,[238] the resource mix is also being affected by the changing economics of the resources that comprise the resource mix.[239]

[237] *See, e.g.*, SREA Initial Comments at 41-42 ("Major utilities in the South, including Entergy, Dominion Energy, Duke Energy, NextEra, Tennessee Valley Authority, and Southern Company have all announced some version of a net zero carbon emission plan or commitment.").

[238] NOPR, 179 FERC ¶ 61,028 at P 45 & n.72 (noting the average levelized cost of wind energy for commercial wind generation has decreased from $90 per MWh in 2009, to $35 per MWh in 2019 (citing Lawrence Berkeley National Laboratory, *Wind Energy Technology Date Update: 2020 Edition*, at 66 (Nov. 2020))); *id.* (noting that the average levelized power purchase agreement price for utility-scale solar generation has decreased from approximately $160 per MWh in 2009, to approximately $40 MWh in 2020 (citing Lawrence Berkeley National Laboratory, *Utility-Scale Solar Data Update: 2020 Edition*, at 32 (Nov. 2020))).

[239] *See* ACORE ANOPR Initial Comments at app. 1, p. 22 (ACEG Jan. 2021 Planning Report) ("Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019."); Dominion Initial Comments at 19 (noting how, during the 2010s, the fracking revolution and advanced technology for natural gas combined cycle generation lead to a shift away from coal and nuclear as "baseload" fuels and how, today, renewable energy resources are likewise undergoing a similar expansion); Evergreen Action Initial Comments at 3 ("Rapid innovation has made wind and solar power the lowest-cost resource in many areas of the country[.]" (citing Univ. of Tex. at Austin Energy Inst., *Levelized Cost of Electricity in the United States by County* (2022), http://calculators.energy.utexas.edu/lcoe_map/#/county/tech); *see also* ACORE Reply Comments at 2 ("In all scenarios, building transmission that enables low-cost wind and other energy resources is often cheaper than the alternatives, such as use of higher-cost but local resources (and potentially additional storage)." (citing Paul Denholm, et al., National Renewable Energy Laboratory, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*, at 47-78 (Sept. 2022))).

99. Together, trends in economics, growing demand, and federal, federally-recognized Tribal, state, and local policies are already resulting in significant changes in the resource mix. The record shows that as of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources.[240] Meanwhile, most of the capacity retirements are, and are projected to continue to be, coal resources.[241] Based on the record, those trends are projected to continue, with over 1,300 GW of wind, solar, and storage resources in interconnection queues across the country as of 2021.[242] With the

[240] SREA Initial Comments at 1-2 (citing US Energy Info. Admin., *Today in Energy* (2021), https://www.eia.gov/todayinenergy/detail.php?id=46416#); *see also* AEE Initial Comments at 13 (noting that between 2011 and 2021, "renewable generation nearly doubled, from 12.5% to more than 20%.").

[241] AEE Initial Comments at 12-13 ("From 2011 to 2021, the proportion of U.S. electricity generated by coal plants dropped by almost half, from 42% to under 22%" (citing U.S. Energy Info. Admin., *U.S. Electricity Generation by Major Energy Source, 1950-2021* (2022), https://www.eia.gov/energyexplained//electricity/charts/generation-major-source.csv)); California Commission Initial Comments at 65 (citing FERC, *State of the Markets 2020* (Mar. 2021); Renewable Northwest Initial Comments at 36 (using IRP data to show that utilities in NorthernGrid plan to retire 6,573 MW of coal, 1,476 MW of natural gas, 10 MW of wind, and 18 MW of solar, by 2040). FERC's State of the Markets 2020 report stated that 9.6 GW of coal capacity retired in 2020, which had a noticeable effect on coal's operating capacity share in most RTOs/ISOs. FERC, *State of the Markets 2020*, at 10, 12 (Mar. 2021). FERC's State of the Markets 2023 indicates that this trend is continuing, with coal generation declining 18.8% in 2023. FERC, *State of the Markets 2023*, at 4 (Mar. 2024). *See also* US DOE Initial Comments at App. B, pp. 8-9 (Rand et al., Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021* (Apr. 2021)).

[242] *See* US DOE Initial Comments app. B, at p. 26 (Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021* (Apr. 2022)) (noting that 676 GW of solar, 246 GW of wind, 213 GW of standalone battery capacity, and ~208 GW of hybrid battery capacity wait in interconnection queues across the U.S.). On the other hand, the number of coal and, relatedly, natural gas resources waiting to interconnect is limited. *See id.*;

passage of the Inflation Reduction Act in 2022, many analysts are predicting that the shift toward renewable resources will accelerate.[243]

100. In light of these changing demands on the transmission system, the record also affirms what the Commission has long recognized: regional transmission planning that identifies more efficient or cost-effective transmission solutions to needs helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions.[244] Conversely,

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Colorado Consumer Advocates Initial Comments attach. 7, at p. 21 ("No new coal plants have been built for domestic utility electricity production since 2014[.]"); NESCOE Initial Comments at 15-16 (noting that new natural gas generation represented nearly 48% of the queue in 2017, but just 3% by March of 2022). Moreover, the updated version of the report to which US DOE cites indicates that the capacity of wind, solar, and storage in interconnection queues is still increasing. Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022* (Apr. 2023) (noting that 947 GW of solar, 300 GW of wind, 325 GW of standalone battery capacity, and ~358 GW of hybrid storage capacity, totaling over 1900 GW, wait in interconnection queues across the country).

[243] ACORE Initial Comments at 1-2 & n.2 ("[P]rojecting annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025- 2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter." (quoting REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, at 15 (2022), https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-12.pdf)).

[244] Order No. 1000, 136 FERC ¶ 61,051 at P 55 ("[T]he narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities."); *id.* P 68 (concluding that reforms that require transmission providers to engage in regional transmission planning and evaluate proposed alternatives that "may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans . . . will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region."); Order No. 890, 118 FERC ¶ 61,119 at P 524 ("[C]oordination

inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill for piecemeal, inefficient, and less cost-effective transmission solutions designed to meet short-term or small-scale transmission needs. Given the magnitude of transmission investment needed to meet customers' changing needs, it is essential that regional transmission planning be of sufficient scope and duration to help to ensure customers' money is well-spent on transmission infrastructure that can efficiently and cost-effectively meet those needs. Unfortunately, we conclude that this is not the case today and that existing regional transmission planning processes are inadequate to address the emerging Long-Term Transmission Needs that are expected to increasingly drive transmission investment in the coming decades.

101. Experience with the implementation of Order No. 1000 over the last decade has highlighted a critical gap in the Commission's existing transmission planning and cost

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of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis."); *see also* ACORE Initial Comments at 6 (demonstrating that effective regional transmission planning could significantly reduce total electric system costs compared to electric system costs that result from intrastate planning (citing Brattle-Grid Strategies Oct. 2021 Report at 12)); R Street Initial Comments at 8 ("[H]olistic transmission planning could improve economic efficiencies and save billions of dollars . . . . For example, MISO's 2022 long-range transmission plan results include $10 billion in transmission projects that support interconnection of 53,000 megawatts of new renewable generation and reduces other costs by $37-$68 billion. PJM similarly identified $3 billion in transmission upgrades that would save billions compared to the current practice of incremental upgrades through the interconnection process." (citing Johannes Pfeifenberger, Brattle Group, *Planning for Generation Interconnection*, at 5 (May 31, 2022), https://www.esig.energy/event/special-topic-webinar-interconnection-study-criteria (citation omitted))).

allocation requirements. Notwithstanding the broad recognition that additional transmission infrastructure is needed to address the drivers noted above, regional transmission planning processes across the country have yielded only limited investments in regional transmission projects. As the Commission observed in the NOPR, investment in regional transmission facilities in some regions has declined compared to prior to Order No. 1000.[245] Moreover, across all the non-RTO/ISO regions, there has not yet been a single transmission facility selected since implementation of Order No. 1000.[246] The record also demonstrates that within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process do occur, much of that investment has been in transmission projects that only address immediate reliability needs.[247] We find that this evidence supports our conclusion that

[245] NOPR, 179 FERC ¶ 61,028 at P 39 (citing ACEG Jan. 2021 Planning Report at 25 & fig. 8); *see also* ACORE ANOPR Initial Comments at 4 ("Despite the potential benefits, regional transmission investment has not increased and in some regions even has declined over the past decade.") (citing ACEG Jan. 2021 Planning Report at 25)); State Agencies Initial Comments at 23 ("Regionally planned projects have [] declined in RTOs/ISOs . . . ." (citing John C. Gravan and Rob Gramlich, NRRI Insights, *A New State-Federal Cooperation Agenda for Regional and Interregional Transmission*, at 2 (Sept. 2021), https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685)).

[246] NOPR, 179 FERC ¶ 61,028 at P 39 (citing LS Power ANOPR Initial Comments App. I at 18 & n.57); FERC, Staff Report, *2017 Transmission Metrics*, at 19 (Oct. 6, 2017), https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf); *see also* Western PIOs Initial Comments at 28 ("The Western Regional Planning Groups, with the exception of the CAISO, have not developed new projects from their current Order 1000 transmission planning process.").

[247] Southwestern Power Group Initial Comments at 15; PIOs ANOPR Initial Comments at 93 & n.276; *see also* Ari Peskoe, *Is the Utility Syndicate Forever?*, 42 Energy L.J. 1, 56-57 (2021) (explaining, for example, that in ISO-NE, all but one of the

existing regional transmission planning processes are not of sufficient scope and duration to adequately or consistently identify transmission needs and associated opportunities to more comprehensively evaluate and select more efficient or cost-effective transmission solutions to those needs.

102. Indeed, in the limited instances in which transmission providers have followed processes that share many of the elements of the long-term, forward-looking, and more comprehensive regional transmission planning this rule requires, customers have seen clear and quantifiable benefits. For example, as the Commission observed in the NOPR,[248] MISO's Multi-Value Project (MVP) transmission planning process proactively planned over a 20-year period for two key drivers of transmission needs: the impacts of changing state laws on the resource mix, and a large increase in the number of generator interconnection requests. To mitigate the uncertainties associated with such long-term projections of transmission needs, MISO relied on scenarios to consider a range of potential future conditions[249] and disclosed the assumptions and inputs underlying each scenario.[250] The MVP process then identified a portfolio of transmission projects that were projected to provide multiple kinds of reliability and economic benefits under all the

transmission projects approved through the regional transmission planning process were immediate-need reliability projects).

[248] NOPR, 179 FERC ¶ 61,028 at PP 30-31 (citing Midcontinent Indep. Sys. Operator, *RGOS: Regional Generation Outlet Study*, at 2 (Nov. 2020)).

[249] *Id.* P 31 (citing MTEP2017 Review at 26-29).

[250] *Id.* (citing MTEP2017 Review at 16).

alternate future scenarios studied.[251] This process resulted in MISO identifying, evaluating, and selecting transmission facilities that are estimated to generate $2.20 to $3.40 of benefit per dollar invested.[252]

103. The benefits to transmission customers of long-term, forward-looking, and more comprehensive regional transmission planning, which we discuss further below, are thus well-documented but realized all too infrequently under existing regional transmission planning processes. Relatedly, the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers,[253] which contributes to rates for transmission that are unjust and unreasonable.

[251] *Id.* (citing MTEP2017 Review at 13).

[252] *Id.* P 30 (citing MTEP2017 Review at 4).

[253] ACORE Initial Comments at 4-5 (citing Brattle-Grid Strategies Oct. 2021 Report at 3); Clean Energy Associations Initial Comments at 5 (explaining that proactive, forward-looking transmission planning processes can reduces costs by nearly half as compared to incremental and reactive transmission planning processes); Ørsted Initial Comments at 5 (explaining that failure to proactively plan for offshore wind results in suboptimal transmission development, which can increase costs to ratepayers); Southeast PIOs Reply Comments at 2 (explaining that in the Southeast, "snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an

104. The record demonstrates that significant expansion of the transmission system is occurring through one-off, piecemeal, interconnection-related network upgrades constructed in response to individual generator interconnection requests.[254] As the Commission observed in the NOPR, the evidence shows a sharp growth in both the total cost of interconnection-related network upgrades and in the cost of such upgrades relative to generation project costs.[255] The record indicates that the average cost of interconnection-related network upgrades is increasing over time as the transmission system is fully subscribed and demand for interconnection service outpaces transmission investment. As highlighted in the NOPR,[256] in 2020, MISO identified the need for nearly $2.5 billion in interconnection-related network upgrades to interconnect just 9.2 GW of generation in MISO South, and MISO expects to need over $3 billion in interconnection-related network upgrades for interconnection in MISO West.[257] Similarly, SPP identified the need for $4.6 billion in interconnection-related network upgrades to interconnect just 10.4 GW of new generation.[258]

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already overburdened populace.").

[254] Pine Gate Initial Comments at 6, 8-10; PIOs Initial Comments at 9 (noting how most transmission planning is done through the generator interconnection process or local transmission planning).

[255] NOPR, 179 FERC ¶ 61,028 at P 37.

[256] *Id.* PP 37-38.

[257] ACORE ANOPR Initial Comments at 10 (citing ICF Sept. 2021 Interconnection Report at 2).

[258] *Id.* (citing ICF Sept. 2021 Interconnection Report at 3-4).

105. Record evidence also shows that increases in interconnection costs are being driven, in many cases, by an expansion in the scope and complexity of interconnection-related network upgrades.[259] The Commission noted in the NOPR, for example, that interconnection-related network upgrade costs in MISO West went from approximately $300/kW in 2016 to nearly $1,000/kW in 2017.[260] The trend is evident in other parts of

[259] *See, e.g.*, US DOE Initial Comments at 8 & n.20 (citing Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy*, at 13-16 (2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf) (ACEG 2021 Interconnection Report); Will Gorman et al., *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*, 135 Energy Policy 110994 (2019), https://www.sciencedirect.com/science/article/pii/S0301421519305816)); ACEG 2021 Interconnection Report at 13 ("[T]he costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than 'driveway' type facilities are need; larger roads and highways are required to alleviate the traffic. . . . [H]istorically, interconnecting wind projects have incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW."); *id.* at 14 ("New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total $307/kW, with upgrade costs for individual interconnection requests as high as $677/kW."); *id.* ("The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were $0.25/MWh and $1.72/MWh, respectively, or $19.07 kW and $61.83/kW, respectively . . . costs for newly proposed wind and solar projects, however, have now risen to $0.69/MWh and $3.66/MWh, respectively or $0.54/kW and $131.90/kW, respectively—more than a 100 percent increase.").

[260] NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 14; NextEra ANOPR Initial Comments at 16 (citing Midcontinent Indep. Sys. Operator, *MISO 2020 Queue Outlook*, at 9 (2020), https://cdn.misoenergy.org/MISO2020InterconnectionQueueOutlook445829.pdf)).

the country as well.[261] The costs of interconnection-related network upgrades are, in many cases, an ever-growing percentage of the total capital costs of new generation projects. According to one report, interconnection costs for new renewable resources were less than 10% of total generation project costs until a few years ago, but recently these costs have risen to as much as 50%-100% of the total generation project costs.[262] At the same time, interconnection-related network upgrades have frequently transitioned from primarily small transmission facilities that serve the needs of a limited number of interconnection customers to the size and scope of what have traditionally been considered high voltage transmission facilities. For example, interconnection-related

[261] NOPR, 179 FERC ¶ 61,028 at P 38 (showing that, as of 2019, interconnection costs in PJM for constructed wind and solar projects were $19.07/kW and 61.83/kW, respectively, as compared to a greater than 100% increase to $54/kW and $131.90/kW, respectively, for projects newly proposed today) (citing *e.g.*, ACEG Jan. 2021 Interconnection Report at 14 & tbl.2)); NextEra ANOPR Initial Comments at 16-17 (stating that interconnection-related network upgrade cost estimates have nearly tripled for newly proposed wind projects, and more than doubled for solar projects in PJM); *see also* ACEG Jan. 2021 Interconnection Report at 16 (illustrating an increase in average interconnection-related network upgrade costs in NYISO from $67/kW in 2013 to $124/kW in 2019). *Compare* ACEG Jan. 2021 Interconnection Report at 15 (identifying interconnection-related network upgrade costs in 2013 in SPP as $89/kW), *with* ICF Sept. 2021 Interconnection Report at 2 (citing interconnection-related network upgrade costs of $448/kW for interconnection customers studied in SPP's system impact study published in April 2021)).

[262] NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 6); *id.* (stating that the rising interconnection costs of wind projects in MISO recently reached approximately 23% of the capital cost of the project) (citing ACEG Jan. 2021 Interconnection Report at 13)); *id.* (identifying the increase in interconnection-related network upgrade costs in SPP between 2013 and 2017 as representing an increase from around 8% to over 43% of the capital cost of wind generation (citing ACEG Jan. 2021 Interconnection Report. at 15)); NextEra ANOPR Initial Comments at 17 (similar)).

network upgrades have recently included demolishing and rebuilding multiple 500 kV transmission lines[263] and constructing long, double-circuit, 765 kV transmission lines,[264] all at significant cost to the interconnection customer initially—and ultimately to consumers.

106. Unlike regional transmission planning processes, however, the generator interconnection process is not designed to consider how to address transmission needs more efficiently or cost-effectively beyond the discrete interconnection request (or requests) being studied. Therefore, the generator interconnection process does not look at time horizons beyond the specific interconnection request(s) being studied, comprehensively assess any transmission needs beyond those created by the specific interconnection request(s), or achieve the economies of scale in transmission investment that long-term, forward-looking, and more comprehensive regional transmission planning processes can provide.[265]

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[263] NOPR, 179 FERC ¶ 61,028 at P 38 (describing interconnection-related network upgrades for a 120 MW solar plus storage project in southern Virginia to interconnect to PJM that cost as much as $12,086/kW (citing ACEG Jan. 2021 Interconnection Report at 15)).

[264] NOPR, 179 FERC ¶ 61,028 at P 38 (describing one interconnection-related network upgrade in SPP identified in the system impact study published in April 2021) (citing ACEG Jan. 2021 Interconnection Report at 15)); ICF Sept. 2021 Interconnection Report at 3 (same); NextEra ANOPR Initial Comments at 17 (same). In 2017, for example, SPP included a 165-mile, $1.34 billion double circuit 765 kV line in its Definitive Interconnection System Impact Study. *See* ACORE ANOPR Initial Comments Ex. 5, ICF Sept. 2021 Interconnection Report at 4.

[265] Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 15 (noting the reactive nature of generator interconnection processes); Exelon Initial Comments at 5 (explaining that the "project-by-project approach of developing

107. We acknowledge that the Commission recently issued Order No. 2023, which requires transmission providers to reform their generator interconnection processes. But while Order No. 2023 aims to improve the efficient processing of interconnection queues, it does not attempt to remedy the discrete deficiency addressed in this final rule: that existing regional transmission planning and cost allocation requirements do not require transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, Order No. 2023 seeks to ameliorate the fact that existing generator interconnection procedures and agreements were "insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner[.]"[266] The interconnection queue backlogs and delays that were the Commission's focus in Order No. 2023 have arisen, in part, due to deficiencies in the existing transmission planning requirements. But the Commission found issues regarding the coordination between transmission planning and

[interconnection-related] network upgrades" using the generator interconnection processes will likely not result in efficient or cost-effective outcomes given the ongoing changes in the resource mix and demand); Pine Gate Initial Comments at 9 (explaining how piecemeal approaches to transmission planning, like the generator interconnection process, result in inefficiently small upgrades (citing ACEG Jan. 2021 Interconnection Report at 7)); PIOs Initial Comments at 10; SEIA Initial Comments at 2; Southeast PIOs Initial Comments at 37 ("The lack of any regular, formal proceeding to consider Alabama Power's comprehensive facility investment plan is troubling and ensures that both generation and transmission are considered on a project-by-project basis. This piecemeal approach to addressing transmission needs for individual generation resource decisions will cause sticker-shock every time and an institutional aversion to broader transmission investment, especially when transmission benefits are expressly ignored.").

[266] Order No. 2023, 184 FERC ¶ 61,054 at P 36.

generator interconnection processes were beyond the scope of Order No. 2023 and, therefore, the Commission addressed only interconnection queue processes rather than also addressing transmission planning requirements.[267] Consequently, this final rule addresses a root cause of interconnection backlogs and delays that Order No. 2023 did not—the failure of transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Accordingly, the need to reform this deficiency persists despite the Commission's reforms required by Order No. 2023.

108. While some commenters argue that transmission providers do not rely too heavily on the generator interconnection process to build transmission facilities,[268] we find that the record indicates otherwise. Specifically, as discussed above, the increase in both the total and average cost of interconnection demonstrates how much transmission investment is occurring on a one-off, incremental basis through generator interconnection processes.[269] The Commission has consistently and repeatedly found that

[267] Order No. 2023, 184 FERC ¶ 61,054 at PP 1741, 1743 (finding that, although "several commenters argue in favor of greater coordination between generator interconnection and transmission planning or identify interconnection as a matter requiring interregional planning," those comments were beyond the scope of that rulemaking proceeding and noting that "the Commission proposed reforms related to coordination between regional transmission planning and cost allocation and generator interconnection in" the docket for this final rule).

[268] Mississippi Commission Initial Comments at 9; North Carolina Commission and Staff Initial Comments at 5; Southern Initial Comments at 38-40.

[269] New Jersey Commission Initial Comments at 6-7 (noting that interconnecting 87.1 GW of capacity, which is needed to meet the PJM states' offshore wind and renewable portfolio standards goals, through the interconnection queue process alone is projected to cost $36 billion); US DOE Initial Comments at 8 (citing ACEG 2021

interconnection-related network upgrades provide systemwide benefits,[270] a finding which courts have upheld.[271] In turn, we find that increasingly relying on interconnection customers' interconnection-related network upgrades to expand the capacity of the transmission system is inefficient and leads to less cost-effective transmission development than would result from long-term, forward-looking, and more comprehensive regional transmission planning, to the detriment of customers.

109. Separately, the record here also substantiates the NOPR's preliminary finding that the majority of investment in transmission facilities since the issuance of Order No. 1000

Interconnection Report at 13-16 (2021)).

[270] *See, e.g.*, *Duke Energy Progress, LLC*, 181 FERC ¶ 61,229, at P 17 (2022) (rejecting Duke's claim that "its customers reap no benefits from network upgrades that must be constructed on Duke's affected system" because "Duke's characterization disregards the existence of any benefits to its customers from the network upgrades"); *ISO New England Inc.*, 150 FERC ¶ 61,209, at P 386 (2015) (noting that there "is a presumption that transmission system enhancements benefit all members of an integrated transmission system"); *Pac. Gas & Elec. Co.*, 106 FERC ¶ 61,144, at P 22 (2004) (explaining that "the integrated grid is a single interconnected system serving and benefitting all transmission customers"); *Pub. Serv. Co. of Colo.*, 62 FERC ¶ 61,013, at 61,061 (1993) ("The Commission has reasoned that, even if a customer can be said to have caused the addition of a grid facility, the addition represents a *system* expansion used by and benefitting *all* users due to the integrated nature of the grid." (emphasis in original)).

[271] *See, e.g.*, *Nat'l. Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) ("We have endorsed the approach of 'assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid."); *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999) ("When a system is integrated, any system enhancements are presumed to benefit the entire system."); *City of Holyoke Gas & Elec. Dep't v. FERC*, 954 F.2d 740, 742-43 (D.C. Cir. 1992); *Me. Pub. Serv. Co. v. FERC*, 964 F.2d 5, 8-9 (D.C. Cir. 1992).

has been in local transmission facilities.[272] Commenters explain that, in RTO/ISO regions, one half of the nearly $70 billion in aggregate transmission investments by Commission-jurisdictional transmission providers between 2013 and 2017 was approved outside of regional transmission planning processes.[273] This investment trend is continuing and accelerating. For example, in 2019, PJM approved 383 transmission-owner planned supplemental projects at a total cost of $3.75 billion, compared to only 80 regionally planned baseline projects at a total cost of $1.27 billion. Then, in 2020, PJM approved 236 supplemental projects at a total cost of $4.7 billion, compared to only 43 regionally planned baseline projects at a total cost of $413 million.[274] In MISO, baseline reliability projects and other local transmission projects have grown dramatically since 2010 and constituted 100% of approved transmission between 2018 and 2020 and 80% since 2010.[275] From 2019 to 2021, 63% of transmission investment by the three largest transmission owners in CAISO was in local transmission projects, and Pacific Gas and Electric forecasts that of the $13 billion it will spend on capital additions between 2022

[272] NOPR, 179 FERC ¶ 61,028 at PP 39-40.

[273] PIOs Initial Comments at 9.

[274] PIOs ANOPR Initial Comments at 31-44; *see also* Ohio Consumers Initial Comments at 5 ("Since 2017, in Ohio, less than 25% of the new investment in transmission has been associated with large regional transmission projects needed for reliability or economic efficiency.").

[275] *See* PIOs Initial Comments at 10 n.31 (citing PIOs ANOPR Initial Comments at 49 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, 2)).

and 2027, approximately 84% will be on local transmission projects.[276] In ISO-NE, spending on in-kind transmission replacements, which are not part of the regional transmission planning process, has been significant. Between 2016 and 2022, over $2.5 billion has been spent on in-kind replacement projects that have entered service and, as of 2022, an additional $3.122 billion of in-kind replacement projects had been proposed, planned, or were under construction.[277]

110. As with the growing reliance on the generator interconnection process to identify needed transmission system improvements, local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs. Similarly, local transmission planning processes and in-kind replacement processes do not generally assess transmission needs based on a forward-looking multi-scenario assessment that more comprehensively accounts for the benefits of transmission infrastructure.[278] Therefore, transmission expansion in this incremental manner also misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission facilities to solve transmission needs, as well as to afford system-wide benefits that may not be achieved through piecemeal, one-off local transmission facilities.

[276] *See* California Commission Initial Comments at 109-110.

[277] NESCOE Reply Comments at 6.

[278] PIOs ANOPR Initial Comments at 33-34 (citing ACEG Jan. 2021 Planning Report); ACEG Jan. 2021 Planning Report at 98-99.

As stated above, the result is relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.

111. To be clear, our findings here are not intended to call into question the justness and reasonableness of either generator interconnection processes or local transmission planning processes, which each serve important roles in ensuring reliability and integrating new resources onto the transmission system.[279] Rather, the trends regarding use of these processes, as well as in-kind replacement processes, provide additional evidence to support our finding that existing regional transmission planning and cost allocation requirements are inadequate without reform. As discussed further in the next section, we conclude that the record regarding the current and projected transmission landscape—including the investment trends and changing drivers of that investment detailed above—highlights critical deficiencies in the Commission's current regional transmission planning and cost allocation requirements. In this final rule, we address those deficiencies to help to ensure that customers receive the benefits of long-term, forward-looking, and more comprehensive regional transmission planning.

[279] As discussed below, we separately find that specific existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential. *See infra* Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

### 2. Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes

112. Based on the record, including comments submitted in response to the NOPR, as discussed below, we find that there is substantial evidence to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis. We find that the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We find that the status quo approach results in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

113. We therefore adopt, as modified by the discussion herein, the preliminary findings of the NOPR concerning the need for reform[280] and, pursuant to FPA section 206,

[280] NOPR, 179 FERC ¶ 61,028 at PP 28-55.

conclude that revisions to the Commission's regional transmission planning and cost allocation requirements are necessary to ensure that Commission-jurisdictional rates, terms, and conditions are just, reasonable, and not unduly discriminatory or preferential. We find that, as stated in the NOPR,[281] absent the reforms instituted by this final rule, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development.

114. Based on the record, including the comments submitted in response to the NOPR, we find that there is substantial evidence to support the conclusion that deficiencies in the Commission's existing regional transmission planning and cost allocation requirements are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential. Specifically, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that these deficiencies render Commission-jurisdictional regional transmission planning and cost allocation processes unjust and

[281] NOPR, 179 FERC ¶ 61,028 at P 33.

unreasonable because they result in transmission providers failing to identify Long-Term Transmission Needs, to evaluate and select more efficient or cost-effective transmission solutions to meet those transmission needs, and to allocate the costs of transmission facilities selected to meet those transmission needs in a manner that is at least roughly commensurate with benefits. Below, we address each deficiency in turn.

115. The first deficiency is that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to perform a sufficiently long-term assessment of transmission needs. This deficiency is present in multiple aspects of existing regional transmission planning processes, from the degree to which planning studies that identify transmission needs are sufficiently forward looking, to whether forward-looking assessments actually inform the evaluation, selection, and eventual cost allocation of regional transmission facilities. The record demonstrates that, under existing regional transmission planning and cost allocation processes, transmission providers typically identify and plan for transmission needs using a relatively near-term transmission planning horizon. Specifically, commenters have noted that most transmission planning regions do not plan beyond a 10-year transmission planning horizon. For example, commenters point out that ISO-NE, SERTP, and NorthernGrid plan using a 10-year transmission planning horizon,[282] while PJM notes that it plans using

[282] Massachusetts Attorney General Initial Comments at 25 ("For example, the Commission's proposal to increase the required long-term transmission planning horizon to at least 20 years with 3-year reassessments would double the current long-term planning horizon for ISO-NE."); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15); Southeast PIOs Initial Comments at 12 ("The 'independent reliability planning studies . . . start with the combined local

two different transmission planning horizons: a 5-year transmission planning horizon for what it refers to as its short-term transmission planning process and a 6-to-15-year transmission planning horizon for what it refers to as its intermediate-term transmission planning process.[283] While it is reasonable and necessary for regional transmission planning and cost allocation processes to include a near-term study of the transmission system, the absence of any consistent and sufficient longer-term assessment of transmission needs prevents transmission providers from identifying Long-Term Transmission Needs and considering regional transmission facilities that may be more efficient or cost-effective solutions to address those needs.[284]

116. This lack of a longer-term assessment of transmission needs is particularly problematic for a few reasons. First, shorter-term transmission planning fails to take

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transmission plans of participating utilities,' and the results comprise the ten-year regional transmission plan." (citation omitted)); Western PIOs Initial Comments at 8-9 ("NorthernGrid conducts transmission reliability plans on a two-year cycle, with each plan covering a 10-year time horizon."); *see also* ITC Initial Comments at 9 (referring to the "broad use of a 10-year planning horizon in the existing transmission planning processes of many major planning regions[.]").

[283] PJM Initial Comments at 2 n.4.

[284] *See, e.g.*, MISO ANOPR Reply Comments at 5 ("[G]iven long-term needs of an evolving system, additional transmission is necessary to reliably serve customers now and into the future. These challenges require immediate action and further delay only increases the risk that system enhancements may not be in place in the timeframe needed."); PIOs Initial Comments at 13 ("[A] short-term outlook under-forecasts longer-term transmission needs, preventing the development of more cost-effective transmission facilities, and fails to consider how the needs of the transmission system are shifting[.]"); US DOE ANOPR Initial Comments at 10 (stating that failure to plan transmission far enough ahead results in "adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals.").

advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide by allowing fewer or better designed transmission facilities to meet multiple transmission needs. For example, shorter-term transmission planning fails to provide the opportunity for transmission providers to identify, evaluate, and select regional transmission facilities that could address multiple transmission needs over various time horizons.[285] Moreover, shorter-term transmission planning fails to create opportunities to "right size" the replacement of aging transmission facilities to address multiple transmission needs over the longer term.[286] Second, constructing large (e.g., high voltage or long distance) transmission facilities comes with long lead times:

[285] ACORE Initial Comments at 4 ("The narrowly focused current approaches [to transmission planning] do not identify opportunities to take advantage of the large economies of scale in transmission that come from 'up-sizing' reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals." (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)); PIOs ANOPR Initial Comments at 10-11; SEIA ANOPR Initial Comments at 14.

[286] ACORE Initial Comments at 4 ("[I]n-kind replacement of aging existing facilities misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies." (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)). PJM's long-term assessment of the transmission system ostensibly uses a 15-year transmission planning horizon, for example, but does not account for changes to the generation mix beyond a 5-year period. *See* Concerned Scientists ANOPR Initial Comments at 10 & n.11 ("Generation additions are unchanged in the 15-year study period, as the input assumption has no additional information that would expand the set of generators included in the forecast."); PSEG ANOPR Initial Comments at 11 (stating that "in practice only new resources that are near the end of the interconnection queue process and have signed an Interconnection Service Agreement are considered in the RTEP base case.").

planning, permitting, and building regional transmission facilities can often take more than ten years.[287] As an example, the MVP initiative in the MISO region took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, and this period of 10 years does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval.[288] Finally, the useful life of transmission assets generally far exceeds even 20 years, so a 10-year transmission planning horizon is much too short to capture all of the benefits that regional transmission facilities can provide.[289]

117. Thus, relying solely on shorter-term transmission planning and studies fails to identify Long-Term Transmission Needs and, consequently, undervalues or entirely ignores the benefits of transmission investments to meet those needs. Moreover, the likelihood that near-term assessments will fail to identify Long-Term Transmission Needs and more efficient or cost-effective regional transmission facilities to meet those needs is higher during periods of rapid change, as the electric sector is now experiencing,

[287] AEP Initial Comments at 11; Nevada Commission Initial Comments at 7 n.24 (noting that it took over seven years between the request to include a transmission line in an Integrated Resource Plan (IRP) and the in-service date, which did not include the lead time for developing the underlying application) PIOs Initial Comments at 14 ("[A] 20-year planning horizon was necessary given the time needed to site, permit, and construct transmission facilities or because states have longer-term public policy goals."); Renewable Northwest Initial Comments at 5; SEIA Initial Comments at 6.

[288] AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio*, at 39 (2021).

[289] SEIA Initial Comments at 6; US DOE Initial Comments at 33 (noting that transmission assets can have a useful life of at least 40 years).

during which the need for transmission infrastructure is expected to grow considerably.[290] We find that continuing with the status quo approach is resulting in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates.[291] As a result, among other things, customers are paying more than necessary or appropriate to meet their transmission needs, forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

118. The second deficiency is that the Commission's existing regional transmission planning and cost allocation requirements fail to require transmission providers to account adequately on a forward-looking basis for known determinants of Long-Term

[290] US DOE ANOPR Initial Comments at 10 ("Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers' expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution."); Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report*, at 6 (July 28, 2022), https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf ("While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.").

[291] *See, e.g.*, *S.C. Pub. Serv. Auth.*, 762 F.3d at 56-59 (explaining that transmission planning processes are practices affecting rates pursuant to Section 206 of the FPA).

Transmission Needs. This deficiency is related to the first deficiency in the sense that both relate to the failure of the existing transmission planning requirements to require transmission providers to adequately plan for the foreseeable future. We find that, even following Order Nos. 890 and 1000, transmission providers have adopted widely divergent approaches to determining the factors that are relevant to identifying transmission needs within regional transmission planning.[292] Specifically, as commenters note, some existing regional transmission planning processes ignore trends in future generation and the impact of extreme weather.[293] Other commenters note that certain regional transmission planning processes ignore state laws or utility goals.[294] In addition

[292] ELCON Initial Comments at 3 ("While regional differences are important to consider, too much flexibility was provided to transmission providers in Order No. 1000 that . . . created a patchwork of planning processes further complicating planning and fostering additional balkanization of the grid[.]"); NOPR, 179 FERC ¶ 61,028 at P 50.

[293] GridLab Initial Comments at 4-5 (noting that SPP does not consider extreme weather events in its transmission plan); Grid Strategies July 2021 Extreme Weather Report at 5 ("[T]ransmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience."); Renewable Northwest Initial Comments at 4, 8 (explaining that regional transmission planning in the Pacific Northwest does not model extreme weather events and generally does not reflect publicly available data such as utility IRPs or carbon reduction goals); *see also* Brattle-Grid Strategies Oct. 2021 Report at 36 (stating that production cost simulations that are typically used to estimate the economic benefit of regional transmission facilities assume no extreme weather events); SPP Market Monitor ANOPR Initial Comments at 3 & n.5 (describing that even SPP's more forward-looking scenario analysis of an emerging technology case in its Integrated Transmission Plan presently underestimates the actual growth of renewables so much that "[w]ind capacity in service today (29.8 GW) already exceeds wind levels projected in both 2019 ITP futures that go out to 2029").

[294] Acadia Center and CLF Initial Comments at 1 ("Order No. 1000 has failed to

to failing to adequately account for factors that shape the resource mix, commenters also assert that current regional transmission planning processes fail to account for factors that will shape future load, particularly new loads associated with electrification trends like, for example, electric vehicles[295] and data centers.[296] Although transmission providers in

require public utility transmission providers to align their transmission planning and funding processes with state policies and objectives." (citing Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms*, at 4 (July 2022), https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf)); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15, which states that WestConnect, for example, does not include planning inputs that extend beyond generic, baseline projects nor "knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets[.]"); SREA Initial Comments at 25 (stating that "SERTP relies entirely on member utilities to self-nominate transmission study requests regarding public policy, meaning if utilities do not provide recommendations or requests, no SERTP study is completed. For instance, in 2021, SERTP stated, '[t]he SERTP did not receive *any input or proposals* for possible transmission needs driven by Public Policy Requirements for the 2021 planning cycle. Therefore, no possible transmission needs driven by Public Policy Requirements have been identified for further evaluation of potential transmission solutions in the 2021 SERTP planning cycle.'" (emphasis in original)).

[295] *See, e.g.*, Clean Energy Buyers Initial Comments at 7-8; National Grid Initial Comments at 8; *see also* AEE ANOPR Initial Comments at 18 (stating that MISO projects electrification effects on load in its long-term regional transmission planning, but how other transmission providers account for electrification trends is not consistent or transparent).

[296] *See supra* note 6; Rocky Mountain Institute Supplemental Comments at 1 ("Technology companies have begun requesting large interconnections for data centers that require increased electricity supply to power generative artificial intelligence."); WIRES Supplemental Comments at attach. 1, p. 36 (Rob Gramlich, et al., *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)) ("Load growth is rising in much of the country, and it is happening in a way that is hard for any single entity to assess on their own. It varies by local area due to factors such as manufacturing plant and data center additions, plus expectations for end-use electrification and penetration of electric vehicles.").

some transmission planning regions account for a wider range of the factors that drive Long-Term Transmission Needs when performing regional transmission planning studies than do others,[297] we find that transmission providers are not consistently or sufficiently accounting on a forward-looking basis for the known determinants of Long-Term Transmission Needs or accounting for such known determinants in a manner that ensures the identification and evaluation of more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

119. We recognize there is inherent uncertainty in forecasting,[298] and we agree with Industrial Customers that current transmission planning is based on known and

[297] *See, e.g.*, Renewable Northwest Initial Comments at 11, 14-15 (discussing how the MISO transmission planning process accounts for the future resource mix); Western PIOs Initial Comments at 23-24, 26-27 (explaining forward-looking aspects of the CAISO transmission planning process).

[298] We acknowledge NRG's comment that forecasting is inherently uncertain. NRG Initial Comments at 10-12. Sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation, however, is better than a lack of planning. The Commission may, by applying its expertise and experience to the record, determine what type and amount of transmission planning results in a just and reasonable rate. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55 ("[I]n rate-related matters, the court's review of the Commission's determination is particularly deferential because such matters are either fairly technical or 'involve policy judgements that lie at the core of the regulatory mission.'" (citing *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009))). "The court owes the Commission 'great deference' in this realm because '[t]he statutory requirement that rates be 'just and reasonable' is obviously incapable of precise judicial definition' and 'the Commission must have considerable latitude in developing a methodology responsive to its regulatory challenge[.]'" *Id.* (citing *Morgan Stanley Cap. Grp. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 532 (2008); *Am. Pub. Gas Ass'n v. FPC*, 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

measurable factors.[299] However, we find, based on this record, that the universe of known and measurable factors that drive regional transmission needs extends beyond those that transmission providers currently consider as part of their regional transmission planning processes. Specifically, the record demonstrates that a multitude of factors like reliability needs driven by the impact of extreme weather, trends in future generation additions and retirements, load growth, federal, federally-recognized Tribal, state, and local laws, and utility goals increasingly shape Long-Term Transmission Needs, are known and identifiable, and have reasonably predictable effects, especially in the aggregate.

120. As noted above, the record shows that the increasing frequency, duration, and intensity of extreme weather events are driving changes in Long-Term Transmission Needs to maintain system reliability.[300] Additionally, demand growth is a major driver of

[299] Industrial Customers Initial Comments at 11.

[300] ACEG Initial Comments at 63 ("[T]he need to improve regional and interregional planning arises from the transformative changes occurring with respect to resource diversity, energy market efficiencies, technological changes, operational innovations and resiliency to withstand severe weather events. If transmission facilities are not constructed, these are all benefits that would otherwise be forfeited."); NERC Initial Comments at 6; Evergreen Action Initial Comments at 2 ("[A]dditional transmission built under improved planning procedures would [] create large reliability benefits. With increasing extreme weather events due to climate change—including wildfires, winter storms, hurricanes, and more—additional transmission infrastructure and grid improvements are increasingly necessary for resilience purposes."); WE ACT Initial Comments at 2 ("Requiring public utility transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events.").

Long-Term Transmission Needs, and contrary to commenter assertions,[301] the record shows that evolving trends in load growth due to data centers, electrification, and industrial growth are driving Long-Term Transmission Needs.[302] Similarly, state laws, utility integrated resource plans and resource procurements, and other regulatory actions necessarily affect Long-Term Transmission Needs for Commission-jurisdictional transmission services.[303] Several commenters also support the broader consideration of anticipated generation retirements and interconnection requests in regional transmission

[301] *See, e.g.*, Industrial Customers Initial Comments at 8-10 (arguing that demand is growing more slowly than in previous periods).

[302] *See, e.g.*, Northwest and Intermountain Initial Comments at 5 n.12 ("For example, Bonneville Power Administration ('BPA') owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA's 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests." (citing BPA, *TSR Study and Expansion Process*, at 12 (Dec. 7, 2021), https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf.)); John Wilson and Zach Zimmerman, *The Era of Flat Demand is Over*, Grid Strategies, at 3, 6 (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf (noting the 5-year load growth forecast has nearly doubled from 2.6% to 4.7% and "transmission investments need to increase just to keep up with demand").

[303] *See, e.g.*, Acadia Center and CLF Initial Comments at 8 ("State laws are . . . essential considerations in planning transmission . . . as state laws drive substantial procurements of energy resources along with the concomitant need for additional transmission, as well as repurposed transmission and non-transmission grid solutions."); AEE Initial Comments at 10 (noting that "[a]s of September 2020, 38 states and the District of Columbia had adopted renewable portfolio standards, and 21 states (plus the District of Columbia and Puerto Rico) – representing more than half of the U.S. population – include a target of 100% renewable energy by 2050 or sooner. Many of these requirements have been enacted in statute and are binding on utilities and retail energy providers.").

planning processes because those factors shape the future resource mix and, therefore, Long-Term Transmission Needs.[304] Relatedly, many commenters highlight the impact of utility goals on the resource mix because such goals will impact transmission needs.[305] Yet, as described above, existing regional transmission planning processes frequently undervalue or entirely omit consideration of some or all of these factors. And while some existing regional transmission planning processes do a better job than others of incorporating different components of long-term, forward-looking, and more comprehensive regional transmission planning, the Commission's existing regional transmission planning requirements do not ensure that factors influencing future transmission will be sufficiently accounted for in that planning.

121. The failure to adequately consider such factors delays planning for the transmission system's changing operational needs until shortly before those transmission needs manifest. As a result, existing transmission planning processes are piecemeal and fail to take advantage of economies of scale in transmission investment or opportunities to address multiple transmission needs over multiple time horizons.[306] We find that

[304] *See, e.g.*, Pattern Energy Initial Comments at 26 ("[T]he generation interconnection queues are indicative of the market and should also be a major source for generation assumptions in scenario planning (both near-term and long-term)."); SEIA Initial Comments at 9.

[305] *See, e.g.*, Renewable Northwest Initial Comments at 6; SREA Initial Comments at 41-46 ("The major utility announcements of achieving net zero or some approximation affects the marketplace, especially in the [S]outheast.").

[306] PIOs Initial Comments at 10-11; Renewable Northwest Initial Comments at 8 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, iv).

engaging in regional transmission planning without adequate consideration of such factors leads to transmission investment that is not more efficient or cost-effective and renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.[307]

122. Third, the record demonstrates that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[308] For example, commenters note that many regional transmission planning processes focus too narrowly only on some benefits.[309]

[307] *See, e.g.*, AEE Initial Comments at 10 ("Failing to take any of [the Commission-proposed factors] into consideration in developing long-term scenarios would risk under investment in needed regional transmission projects to meet transmission needs and potential[ly] result in unjust and unreasonable rates for transmission service."); New Jersey Commission Initial Comments at 3-9 (arguing that "[e]nsuring just and reasonable rates requires mandating long-term, multi-value, and portfolio based transmission planning.").

[308] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 624 (declining to prescribe "a particular definition of 'benefits'").

[309] Massachusetts Attorney General ANOPR Initial Comments at 22 ("New England's siloed approach to transmission planning inhibits identification of multi-value solutions." As part of ISO-NE's Boston 2028 Request for Proposals, "[i]n focusing on cost-effectively solving reliability needs alone, ISO-NE rejected all but one of thirty-six proposals. While ISO-NE rejected some of these proposals for technical reasons, it eliminated several due to cost considerations alone."); PIOs Initial Comments at 10 ("[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs . . . . [M]ultiple quantifiable benefits to transmission . . . are being ignored in the transmission planning process.").

For instance, the Brattle-Grid Strategies Report concludes that "most of [the nation's recent transmission] investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits."[310] As PIOs argue, the Commission's existing regional transmission planning and cost allocation requirements do not require that transmission providers assess "opportunities to benefit from economies of scale that come from 'right-sizing' and strategic, comprehensive planning of transmission portfolios and projects to capture additional benefits. . . ."[311] Other regional transmission planning processes fail entirely to consider cost savings associated with certain transmission facilities.[312]

123. Based on the record, we find that, as with the universe of known and measurable factors driving transmission needs, the benefits that regional transmission facilities provide extend beyond those benefits that transmission providers currently consider as

[310] Brattle-Grid Strategies Oct. 2021 Report at 2.

[311] PIOs Initial Comments at 10-11. The benefits cited by PIOs "include congestion relief, reduced transmission losses, resiliency to extreme weather events, increased flexibility to respond to changing market or system conditions, and facilitating larger regional or interregional solutions for cost effective interconnection of the renewable and storage resources needed to meet public policy goals." *Id.* at 11.

[312] SREA Initial Comments at 24 ("SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the 'Economic Planning Studies' only evaluate the costs of potential upgrades to the system, but none of the benefits.").

part of their regional transmission planning and cost allocation processes.[313] Failing to adequately identify and consider the benefits of such transmission facilities may lead to relatively inefficient or less cost-effective transmission development. In particular, the cost-benefit analyses that transmission providers often use as part of the evaluation process may fail to identify more efficient or cost-effective regional transmission facilities for selection because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities. Thus, the failure to adequately consider the benefits of regional transmission facilities results in, among other things, transmission customers forgoing benefits that may significantly outweigh their costs, which results in less efficient or cost-effective transmission investments and, in turn, contributes to Commission-jurisdictional rates that are unjust and unreasonable.

124. Given our findings above concerning the deficiencies in existing transmission planning requirements, and our conclusion that long-term, forward-looking, and more comprehensive regional transmission planning is needed, we also conclude that existing cost allocation requirements are deficient and must be modified to properly account for Long-Term Regional Transmission Planning. The Commission has long recognized the

[313] We disagree with Potomac Economics' arguments that the sole benefit of transmission is alleviating congestion and that congestion is primarily an economic issue, so investment in alleviating congestion should not exceed the benefit of doing so. *See* Potomac Economics Initial Comments at 3-4. As discussed *infra* in the Evaluation of the Benefits of Regional Transmission Facilities section alleviating congestion is just one of many potential benefits that transmission infrastructure provides, and transmission benefits beyond solving congestion are considered by transmission providers in regional transmission planning processes today.

"close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan,"[314] and that cost allocation issues will often determine whether transmission providers and customers support the construction of new facilities.[315] Furthermore, experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states. As the Commission discussed in the NOPR and we continue to find in this final rule, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[316]

125. Given the link between cost allocation and transmission planning, it is essential that cost allocation requirements for Long-Term Regional Transmission Facilities are appropriately tailored to the new Long-Term Regional Transmission Planning requirements of this rule, particularly given the anticipated long-lead time for any regional transmission facilities developed and regionally cost allocated through this final rule. Without proper alignment of the regional transmission planning and cost allocation requirements, it is less likely that transmission facilities selected in Long-Term Regional

[314] Order No. 1000, 136 FERC ¶ 61,051 at P 496.

[315] Order No. 890, 118 FERC ¶ 61,119 at P 557; *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 496.

[316] NOPR, 179 FERC ¶ 61,028 at P 301; *infra* Regional Transmission Cost Allocation section.

Transmission Planning will be developed, which would undermine the essential purpose of the regional transmission planning process, namely, the development of more efficient or cost-effective regional transmission facilities.

126. We find that the Commission's current cost allocation requirements, which were designed and established in the context of existing Order No. 1000 regional transmission planning processes, are insufficient to appropriately allocate costs associated with regional transmission facilities that are selected in accordance with the new Long-Term Regional Transmission Planning requirements that we establish in this final rule. The Commission's existing Order No. 1000 cost allocation requirements contemplate the application of differing cost allocation methods to different types of transmission facilities. But we find that Long-Term Regional Transmission Planning, which accounts for multiple drivers of Long-Term Transmission Needs and results in Long-Term Regional Transmission Facilities that produce a broader set of benefits, warrants a different approach to cost allocation for such transmission facilities. Likewise, existing Order No. 1000 regional transmission planning processes do not mandate the consideration of specific benefits that we believe are appropriately considered as part of Long-Term Regional Transmission Planning. New information concerning these benefits uncovered through the transmission planning process may be relevant when allocating the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with their benefits.[317] Importantly, existing cost allocation

[317] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (*ICC v. FERC I*); Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional

requirements do not provide a dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods. We conclude such a role is particularly relevant to Long-Term Regional Transmission Planning, given: (1) the lengthy planning horizon over which transmission projects might be identified, selected, and ultimately constructed; (2) the resultant increased uncertainty for Long-Term Regional Transmission Facilities; and (3) accordingly, the increased importance for state engagement regarding cost allocation to increase the likelihood such facilities obtain needed siting approvals from the states and are thus timely and cost-effectively developed. We therefore believe that it is both necessary and appropriate to establish specific cost allocation requirements that are tailored to the Long-Term Regional Transmission Planning reforms in this final rule.

127. Based on the record, including comments submitted in response to the NOPR, we find that there is substantial evidence demonstrating that Long-Term Regional Transmission Planning and cost allocation to identify and plan for Long-Term Transmission Needs does not occur on a consistent and sufficient basis.[318] We find, in

transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

[318] *See* New Jersey Commission Initial Comments at 8 (explaining that, outside of limited circumstances, PJM, Florida, ISO-NE, Southeastern Regional, South Carolina Regional, WestConnect, NorthernGrid, NYISO, SPP, and CAISO do not conduct multi-driver or portfolio transmission planning, which has required ratepayers to pay for tens of billions of dollars in unnecessary transmission projects); NextEra ANOPR Initial Comments at 71 ("While there are examples of longer-term planning currently being utilized by some regions, such as MISO's annual 15-year Futures assessment or SPP's 20-year Integrated Transmission Plan run every five years, there is no standard as to what time horizon long-term planning must study, nor how often this planning should be done.

large part, that this is because of the deficiencies that we have identified above in the Commission's existing regional transmission planning and cost allocation requirements. In addition, we find that, in the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes, transmission providers are meeting many transmission needs by identifying transmission solutions and developing transmission facilities through other processes, i.e., outside of the regional transmission planning and cost allocation processes,[319] or, as discussed above, in response to near-term reliability needs,[320] which may not identify the more-efficient or cost-effective solution.

128. To reiterate, the fact that transmission facilities are being identified and built outside of regional transmission planning processes and in response to near-term reliability needs is not inherently problematic. In many instances, as some commenters

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Further, no standards or guidelines exist as to what should be included in such long-term planning to ensure that customers are charged just and reasonable rates for the most efficient and cost-effective investments given the most comprehensive and up-to-date information available."); Western PIOs Initial Comments at 4-28 (arguing that in the Western United States transmission planning outside of CAISO is not developed and is ineffective); Brattle-Grid Strategies Oct. 2021 Report at 13-15 & tbl. 2 (documenting inconsistent "use of proactive, scenario-based, multi-value processes" across various planning authorities, including NYISO, CAISO, MISO, PJM, ISO-NE, Florida, Southeast Regional, and South Carolina").

[319] *See, e.g.*, LS Power Initial Comments at 46-50; PIOs Initial Comments at 9-10 (explaining that about half of the approximately $70 billion in aggregate transmission investment by Commission-jurisdictional transmission owners in RTO/ISO regions was approved outside of regional transmission planning processes).

[320] *Supra* note 309.

point out,[321] those processes may be well equipped to identify necessary and appropriate transmission solutions. Rather, the problem is that incremental and piecemeal expansion of the transmission system outside of regional transmission planning process misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to solve Long-Term Transmission Needs, as well as to afford system-wide benefits that may not be achieved through one-off transmission system upgrades.[322] To the extent that transmission providers may not be identifying and evaluating the more efficient or cost-effective transmission solutions needed to meet underlying transmission needs, including Long-Term Transmission Needs, over time, consumers will bear the costs of relatively inefficient or less cost-effective piecemeal transmission investment and expansion.[323]

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[321] *E.g.*, Duke Initial Comments at 7.

[322] *See, e.g.*, ACORE Initial Comments at 8 ((“For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective.”) (quoting Brattle-Grid Strategies Oct. 2021 Report at 30)); Clean Energy States Initial Comments at 2 (“[T]he one-plant-at-a-time approach to transmission upgrades results in a patchwork approach that drives up costs and misses opportunities for improvements to the system as a whole.”); Exelon Initial Comments at 5.

[323] Michigan State Entities Initial Comments at 1-2 (explaining concerns that the lack of long-term transmission planning has led to significantly higher residential rates and how the problem will worsen if transmission investment does not reflect changes in the resource mix and demand); New Jersey Commission Initial Comments at 6-7 (noting PJM analysis showing transmission upgrades to interconnect 87.1 GW of a variety of resources, including offshore wind, would cost $3.2 billion if done through holistic transmission planning whereas connecting only 15.4 GW of offshore wind would cost $6.4 billion if done through the interconnection queue process, and estimating that the interconnection of 87.1 GW through the interconnection queue would increase the cost to

129. We find that the concerns arising from the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes and the corresponding failure by transmission providers to identify and evaluate more efficient or cost-effective transmission solutions to Long-Term Transmission Needs are exacerbated by the fact that transmission needs in most transmission planning regions are drastically changing. Contrary to the claims of some commenters, we are not promulgating this rule in an attempt to steer the resource mix and demand[324] based on a preference for certain resources over others.[325] Instead, the

consumers by over $30 billion compared to holistic transmission planning); PIOs Initial Comments at 8 (noting how deficiencies in the Commission's regional transmission planning processes have "led to billions of dollars in excessive costs for consumers." (citing Brattle-Grid Strategies Oct. 2021 Report at 1-13 (Section 1)).

[324] Consumer Organizations Initial Comments at 1-2; ELCON Initial Comments at 9; SERTP Sponsors Initial Comments at 16-20. *But see* SEIA Reply Comments at 2-3 ("The NOPR does make 'repeated references' to the changing resource mix. But that is not because the NOPR will 'promote a transition to a more renewables-heavy electric system.' The NOPR makes these references because the resource mix is, in fact, changing. The question before the Commission is not whether to promote or impede that change, but how to address the needs of the grid as a result of that inevitable change." (internal quotations omitted)); New Jersey Commission Reply Comments at 2 ("The Commission is . . . trying to ensure the electricity system can reliably and efficiently achieve the generation mix that state policymakers and voluntary consumers—not the Commission—have chosen. Ensuring that these customers are served at the lowest possible cost while maintaining reliability is entirely consistent with and indeed required in order to meet the dictates of the FPA. In other words, the Commission is acting to ensure transmission planning processes account for current realities and meet evolving consumer needs at a total cost that is just and reasonable." (internal citations omitted)).

[325] *See, e.g.*, Ohio Commission Federal Advocate Initial Comments at 4-6 (arguing that the Commission's purpose in issuing the NOPR was to promote an aspirational renewable future and achieve narrow environmental objectives); Undersigned States Reply Comments at 7 (arguing that the Commission is forcing ratepayers to subsidize

Commission is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's jurisdiction or control, including, but not limited to, the increasing frequency of extreme weather events, customer preferences, demand growth, economic and technological trends, and federal, federally-recognized Tribal, state, and local policies.[326]

130. In response to commenters, we acknowledge that integrated resource planning processes, where they exist, shape the resource mix and can often include forms of proactive transmission planning. As stated in Order No. 1000, we reiterate that "the regional transmission planning process is not the vehicle by which integrated resource planning is conducted."[327] Indeed, this final rule does not aim to affect—either facilitate or hinder—any changes or decisions that occur outside of the Commission's jurisdiction. Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential. To this

forms of energy by socializing the cost of a transmission build out).

[326] *See* New Jersey Commission Initial Comments at 3 ("The Commission is not proposing to unduly favor, mandate, or subsidize forms of generation but is rather seeking to ensure that the bulk electricity system maintains reliability and satisfies evolving consumer demand . . .").

[327] Order No. 1000, 136 FERC ¶ 61,051 at P 154.

end, this final rule is focused on ensuring that regional transmission planning processes are adequately *accounting for* the changes occurring outside of the Commission's jurisdiction, including the resource decisions that are the exclusive jurisdiction of states.[328] Additionally, to the extent that integrated resource planning processes include forms of transmission planning, such planning can be complementary to Commission-jurisdictional regional transmission planning processes but cannot take the place of such processes. This is not to diminish the importance of integrated resource planning processes, which serve a critical role in shaping the generation mix and transmission infrastructure. In recognition of this role, this final rule requires transmission providers to consider integrated resource planning as a factor when conducting Long-Term Regional Transmission Planning. But, as discussed below, we conclude that integrated resource planning is appropriately considered as *one of several* categories of factors used to develop Long-Term Scenarios and identify Long-Term Transmission Needs.

131. In response to commenters that argue regional transmission facilities may not address local transmission needs such that a local transmission facility would still be needed,[329] we acknowledge that regional transmission facilities are not necessarily always

[328] *See PJM Power Providers Grp. v. FERC*, 88 F.4th 250, 275 (3d Cir. 2023) (holding that the Commission is "unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus . . . ."); *see also Elec. Power Supply Ass'n v. Star*, 904 F.3d 518, 524 (7th Cir. 2018) (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois "as givens and set out to make the best of the situation [these systems] produce").

[329] *See, e.g.*, Duke Initial Comments at 9 (arguing that there are instances in which

a more efficient or cost-effective solution to address local transmission needs, and nothing in this final rule requires transmission providers to rely on regional transmission facilities to address exclusively local transmission needs. Instead, this final rule identifies deficiencies in existing Commission-jurisdictional regional transmission planning processes that lead transmission providers to fail to identify Long-Term Transmission Needs and fail to identify, evaluate, or select more efficient or cost-effective transmission solutions to meet those transmission needs. As a result of these deficiencies, transmission providers may undertake relatively inefficient investments in transmission infrastructure by missing opportunities to identify regional transmission facilities that bring economies of scale or address multiple transmission needs over different time horizons, including local transmission needs.

132. We disagree with arguments that the Commission cannot promulgate this final rule because we rely on general findings, rather than individualized analyses of each, specific transmission planning region.[330] Relevant precedent, including regarding the Commission's comparable action in Order No. 1000, is clear that the Commission has discretion as to the procedural means through which it will apply its substantive expertise, and we need not make findings that are region specific in every case; rather, we are empowered to "rely on 'generic' or 'general' findings of a systemic problem to

larger regional transmission projects may not resolve localized transmission needs).

[330] *See, e.g.*, Louisiana Commission Reply Comments at 5-6; NRECA Initial Comments at 14-16.

support imposition of an industry-wide solution,"[331] and we do so here. The fact that individual transmission planning regions may have different forms of transmission planning processes, and may experience varying levels of transmission investment, would be "as unastonishing as it is irrelevant."[332] Moreover, although transmission planning practices vary considerably between transmission planning regions and some regions may engage in transmission planning that shares many of the elements of the more long-term, forward-looking, comprehensive regional transmission planning required in this rule, the record demonstrates that this final rule identifies deficiencies that reach well beyond "isolated pockets[.]"[333] Rather, the record demonstrates that these deficiencies pervade large swaths of the country, which include RTO/ISO and non-RTO/ISO transmission planning regions.[334] Accordingly, this final rule's remedy does not present an "extreme 'disproportion of remedy to ailment[.]'"[335] The Commission may reasonably rely on a rulemaking procedure to address the industry-wide changes to the transmission landscape, notwithstanding regional variation among regional transmission planning processes. As the Commission stated in Order No. 1000, "[i]t is well established that the

[331] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (quoting *Interstate Nat. Gas v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002)).

[332] *Id.* (quoting *Wis. Gas v. FERC*, 770 F.2d 1144, 1157 (D.C. Cir. 1985)).

[333] *Id.*

[334] *See, e.g.*, *supra* notes 283 and 284 (explaining that ISO-NE, SERTP, Northern Grid, and PJM undergo transmission planning using time horizons shorter than 20 years).

[335] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67.

choice between rulemaking and case-by-case adjudication 'lies primarily in the informed discretion of the administrative agency.'"[336] The Commission also stated that "[i]t is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry wide problems facing us."[337] Moreover, we agree with ACEG that pursuing region-specific solutions will lead to "siloed and disjunctive transmission planning policies [that] will not solve the problems facing the nation's electric grid."[338]

133. Furthermore, although not every transmission planning region is experiencing these changes in equal measure, the record shows that significant changes are well underway nationwide, and that failing to adequately account for Long-Term Transmission Needs poses a risk to just and reasonable rates throughout the country.[339] In fact, the record raises a wide range of concerns, and the Commission need not, and should not, wait for systemic problems to undermine regional transmission planning in every region before it acts.[340] The record in this proceeding confirms that significant investments in new transmission facilities are expected to occur, with substantial impacts

[336] Order No. 1000, 136 FERC ¶ 61,051 at P 60.

[337] *Id.*

[338] ACEG Reply Comments at 17.

[339] AEE Reply Comments at 3-4.

[340] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 50.

on the Commission-jurisdictional rates that customers pay.[341] It is therefore critical, and it is the Commission's responsibility, to act now to address deficiencies in its regional transmission planning and cost allocation requirements to ensure that more efficient or cost-effective transmission investments are made as the industry addresses the changing landscape.[342]

### 3. Benefits of Long-Term Regional Transmission Planning and Cost Allocation to Identify and Plan for Long-Term Transmission Needs

134. Upon consideration of the record, we find that the requirements set forth in this final rule will address deficiencies in the existing regional transmission planning and cost allocation requirements and will promote enhanced reliability and more efficient or cost-effective transmission solutions, which will help to ensure just and reasonable Commission-jurisdictional rates.

135. The record demonstrates that long-term, forward-looking, and more comprehensive regional transmission planning that identifies Long-Term Transmission Needs will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to those needs. For example, like the Commission in the NOPR,[343] commenters cite to the success of MISO's Long-Range Transmission Plan in delivering more efficient or cost-effective transmission solutions. By addressing

[341] *See supra* P 93.

[342] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 46.

[343] *See, e.g.*, NOPR, 179 FERC ¶ 61,028 at PP 31-32.

public policy, economic, and reliability transmission planning needs simultaneously through its MVP category, MISO "'eliminate[d] the need for $300 million in future baseline reliability upgrades,' and provided production cost savings that *exceeded the entire cost of the portfolio by $10 billion*."[344] Brattle Group and Grid Strategies also found that "building out piecemeal network upgrades through the interconnection queue process to integrate the same amount of generation would have cost over 80% more than the cost of the MVP portfolio."[345] Similarly, the New Jersey Commission asserts that, by planning transmission facilities to address a specific set of known and identified transmission needs through a holistic portfolio, rather than piecemeal through the generator interconnection process, PJM could save customers more than $30 billion.[346]

136. We note that the cost-saving results that MISO experienced were the direct product of more comprehensive, longer-term regional transmission planning. By

[344] New Jersey Commission Initial Comments at 4 (citing MTEP2017 Review at 6, 8) (emphasis in original).

[345] *Id.* at 4-5 (citing Brattle-Grid Strategies Oct. 2021 Report at 7 & nn.13-14); *see id.* at 5 n.9 (noting that the cost of the MVP portfolio divided by the amount of wind capacity it interconnected came to $412 per kilowatt, while interconnection-related network upgrades for new generation in MISO planned through the interconnection queue cost $756 per kilowatt).

[346] *Id.* at 6-7 (citing Brattle-Grid Strategies Oct. 2021 Report at 7); *id.* (explaining that the onshore network upgrades required to interconnect 87.1 GW of resources meeting all of PJM states' current offshore wind goals and total renewable portfolio standards through "piecemeal interconnection queue projects would cost nearly $36 billion in total—*more than eleven times* the $3.2 billion cost of the integrated portfolio approach," or "[p]ut another way, proactive, portfolio-based planning in PJM could ultimately save ratepayers over $30 billion compared to the status quo.").

expanding the transmission planning horizon and considering factors affecting Long-Term Transmission Needs, as well as considering a broader list of benefits, transmission providers will be able to identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs.[347] Such Long-Term Regional Transmission Planning will: (1) reduce reliance on transmission solutions that are relatively inefficient or less cost-effective because they address only short-term transmission needs; (2) unlock the benefits of economies of scale in transmission investment;[348] (3) enable opportunities to "right size" replacement transmission facilities;[349] (4) facilitate the selection of regional transmission facilities that could address multiple transmission needs over different time horizons; and (5) provide states, utilities, customers, and other stakeholders with greater insight and transparency into the costs and benefits of particular transmission solutions to address Long-Term Transmission Needs. We conclude that these regional transmission planning and cost allocation reforms will benefit customers by leading to more efficient or cost-effective transmission investment, thereby helping to ensure just and reasonable rates.[350]

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[347] PIOs Initial Comments at 35.

[348] *Id.* at 10 ("[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs.").

[349] ACEG Initial Comments at 53-56; Clean Energy Associations Initial Comments at 25-27; SEIA Initial Comments at 25-26.

[350] *See, e.g.*, Exelon Initial Comments at 5 ("The project-by-project approach of developing [interconnection-related] network upgrades in response to generator

137. In addition to potentially enhancing the efficiency and cost-effectiveness of transmission investment, we find that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes will enhance reliability. In the NOPR, the Commission found that a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity. The record supports this conclusion. Many commenters agree that, especially in light of continuing changes in both supply and demand, ongoing investment in regional transmission facilities is necessary to ensure that the transmission system continues to serve load in a reliable manner at reasonable cost.[351] Commenters also agree that regional transmission investments support enhanced reliability because larger, more

interconnection requests does not take into account broader, longer-term planning needs and furthermore raises questions about whether it will lead to efficient and cost-effective outcomes as the resource mix rapidly evolves."); PIOs Initial Comments at 8 ("[O]verwhelming evidence indicates that transmission owners are largely able to evade the requirements of Order No. 1000 and . . . have primarily invested in local projects. This has led to . . . billions of dollars in excessive costs for consumers." (citing Brattle-Grid Strategies Oct. 2021 Report at Section 1)); Southeast PIOs Reply Comments at 2 ("All the while, snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an already overburdened populace.").

[351] ACORE ANOPR Initial Comments at 21-22 (explaining how additional transmission investments can alleviate billions of dollars in costs caused by extreme weather); EEI Initial Comments at 4 ("Transmission plays and will continue to play a vital role in enabling the energy transition and in ensuring a reliable and resilient energy grid. A robust transmission system will not only enable electric utilities to integrate more renewable energy resources and deliver more clean energy to customers but will also enhance the reliability and resiliency of the grid and enable the deployment of new technologies." (citing EEI, *Planning and Developing Electric Transmission Projects: The Path to the Grid of the Future* (2022)); NERC Initial Comments at 6 (explaining that transmission will be key to managing a reliable transformation in the resource mix).

integrated transmission systems are better equipped to accommodate a diversity of supply and demand conditions and provide redundancy that allow the system to better withstand unpredictable and extreme weather events, which are occurring with increased frequency and severity.[352]

138. Moreover, commenters provide examples of how long-term, forward-looking, and more comprehensive regional transmission planning can better identify reliability needs and resolve these needs with more efficient or cost-effective transmission solutions.[353] For example, as noted above, MISO's MVP Portfolio 4 eliminated the need for $300 million in future baseline reliability upgrades.[354] By comparison, the Reliability Must-Run Agreement for Indian River Unit 4, a 410 MW coal-fired generation unit, highlights the costs of inadequate regional transmission planning. As NARUC explains, the Indian River Unit 4 was scheduled to retire, but PJM found that retirement would cause

[352] NERC Initial Comments at 6 (explaining that regional transmission planning is necessary to ensure sufficient transmission capacity to move energy from areas with a surplus to areas that are deficient).

[353] ITC Initial Comments at 44 ("While local transmission planning continues to serve a critically necessary, valuable function in maintaining the reliability and efficiency of transmission systems, it is nonetheless clear that holistic, long range transmission planning is far more capable of identifying optimal transmission solutions that serve the most needs and deliver the most benefits."); MISO Initial Comments at 88 (explaining that in its Tranche 1 Long Range Transmission Plan, MISO recognizes Avoided Transmission Investment benefits provided by Long Range Transmission Plan facilities in addressing both avoided reliability projects and avoided age and condition replacement projects with the results being avoided costs in local transmission that would have otherwise been incurred to replace existing facilities).

[354] New Jersey Commission Initial Comments at 4.

reliability issues and would necessitate upgrades to transmission facilities that, due to their age, were already due to be upgraded, and that the Reliability Must-Run Agreement was needed because those upgrades would take five years to complete.[355] A long-term, forward-looking, and more comprehensive regional transmission planning process may have obviated the need for the Reliability Must-Run Agreement, the individual transmission facility upgrades, or both.

#### 4. Conclusion

139. In consideration of the record provided in this proceeding, as well as the related conclusions stated above, we find that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential because they fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis. Specifically, as discussed, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that reforms to those requirements are thus necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly

[355] NARUC Initial Comments at 14-15.

discriminatory or preferential. The failure to plan on a sufficiently long-term, forward-looking, and comprehensive basis results in the potential for relatively inefficient or less cost-effective transmission development for which customers must pay. The requirements set forth in this final rule will help to ensure that transmission providers plan to address Long-Term Transmission Needs, in turn helping to ensure more efficient or cost-effective transmission development and thus just and reasonable Commission-jurisdictional rates.

## III. Long-Term Regional Transmission Planning

### A. Requirement to Participate in Long-Term Regional Transmission Planning

#### 1. NOPR Proposal

140. In the NOPR, the Commission proposed to require each transmission provider to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning,[356] meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify transmission needs driven by changes in the resource mix and demand and to identify and evaluate transmission

[356] The two features of Long-Term Regional Transmission Planning that the Commission included in the proposed reforms were the development of scenarios with a 20-year transmission planning horizon to be reassessed and revised every three years, with each such re-assessment providing the basis for identification and evaluation of transmission facilities for potential selection. NOPR, 179 FERC ¶ 61,028 at P 68 n.128.

facilities for potential selection as the more efficient or cost-effective transmission facilities to meet such needs.[357]

141. The Commission proposed that transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.[358]

142. The Commission proposed that transmission providers that comply with the Long-Term Regional Transmission Planning requirements will comply with the requirement in Order No. 1000 that they participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.[359] The Commission further proposed to allow transmission providers to propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes they use to consider transmission needs driven by Public Policy Requirements.[360] The Commission stated, however, that such continued use of existing regional transmission planning and cost allocation processes would not supplant transmission providers' obligations to comply with the Long-Term Regional Transmission Planning requirements established in any

[357] *See id.* PP 54, 64, 68.

[358] *Id.* P 72.

[359] *Id.* P 73.

[360] *Id.* P 74.

final rule in this proceeding. Moreover, the Commission proposed that transmission providers seeking to retain existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements would have to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning proposed in the NOPR by demonstrating that continued use of such processes is consistent with or superior to any final rule issued in this proceeding.[361]

143. The Commission preliminarily found that transmission providers could propose a regional transmission planning process that plans for reliability needs, economic needs, transmission needs driven by Public Policy Requirements, and transmission needs driven by changes in the resource mix and demand simultaneously through a combined approach. The Commission stated that transmission providers proposing to address all such transmission needs in a single regional transmission planning process would bear the burden of demonstrating continued compliance with Order No. 1000 in addition to compliance with the requirements of any final rule in this proceeding.[362]

144. Finally, the Commission proposed to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000

[361] *Id.*

[362] *Id.* P 75.

transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[363]

### 2. Comments

#### a. General Comments

145. The majority of commenters support the Commission's proposal,[364] with multiple commenters claiming that Long-Term Regional Transmission Planning is crucial to

[363] *Id.* P 76.

[364] Acadia Center and CLF Initial Comments at 2; ACEG Initial Comments at 6, 22-23; ACORE Initial Comments at 2, 17; Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 5-7; Amazon Initial Comments at 2; BP Initial Comments at 4-7; Breakthrough Energy Initial Comments at 3; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2-4; California Energy Commission Initial Comments at 1; City of New Orleans Council Initial Comments at 4; City of New York Initial Comments at 1, 3; Clean Energy Associations Initial Comments at 10; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy – Florida Supplemental Comments at 1; Conservatives for Clean Energy – South Carolina; CTC Global Initial Comments at 1; US Senators Supplemental Comments at 1-2; EEI Initial Comments at 10; ELCON Initial Comments at 6-7; NERC Initial Comments at 6-7; ENGIE Initial Comments at 2; Entergy Initial Comments at 7; Environmental Groups Supplement Comments at 2; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 2; Exelon Initial Comments at 4-7; Form Energy Initial Comments at 2-3; Governor of Kansas Laura Kelly Supplemental Comments at 1; Handy Law Initial Comments at 7-8; US House Republicans Supplemental Comments at 1; Indicated PJM TOs Initial Comments at 7-8; Indicated US Senators and Representatives Initial Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; ISO-NE Initial Comments at 2, 8; ITC Initial Comments at 5-9; Joint Consumer Advocates Initial Comments at 5-6; Minnesota State Entities Initial Comments at 4; NARUC Initial Comments at 4; National Grid Initial Comments at 9-11; NEMA Initial Comments at 1-2; NESCOE Initial Comments at 14-16; New England for Offshore Wind Initial Comments at 2; New York Commission and NYSERDA Initial Comments at 8; New York TOs Initial Comments at 1; New York Transco Initial Comments at 1; NextEra Initial Comments at 62; Northwest and Intermountain Initial Comments at 7; Ohio Conservative Energy Forum Supplemental Comments at 1; Pine Gate Initial Comments at 18-19; PIOs Initial Comments at 12-14; Policy Integrity Initial Comments at 5; RMI Supplemental

ensure that regional transmission planning appropriately identifies transmission needs to meet the changing resource mix and demand.[365]

146. AEP and Ørsted argue that the Commission's proposal will address deficiencies in the current transmission planning process.[366] National Grid claims that existing long-term transmission planning processes are sufficient for addressing reliability and economic transmission needs in the near-term but are inadequate for addressing the changing resource mix and demand, as well as for addressing resilience challenges driven by climate change.[367] ACEG claims that Long-Term Regional Transmission Planning will allow right-sizing of transmission facilities.[368]

147. Some commenters observe that this proposal may result in cost-savings for consumers. For example, DC and MD Offices of People's Counsel claim that this

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Comments at 2; Senator Schumer Supplemental Comments at 1-2; Senator Whitehouse Supplemental Comments at 1-3; SDG&E Initial Comments at 2; Southeast PIOs Initial Comments at 42-49; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 1-2; Vermont Electric and Vermont Transco Initial Comments at 3; Virginia Commission Staff Initial Comments at 2-3; Western PIOs Initial Comments at 28-30, 36; Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[365] Breakthrough Energy Initial Comments at 12; EEI Supplemental Comments at 1; Exelon Initial Comments at 5; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 5.

[366] AEP Initial Comments at 8; Ørsted Initial Comments at 4-5.

[367] National Grid Initial Comments at 10.

[368] ACEG Initial Comments at 6.

proposal could result in significant cost savings to consumers by helping address severe weather events and reduce the relative cost of decarbonizing the country's resource fleet.[369] AEP argues that the NOPR proposal will benefit consumers by establishing a process that will identify more efficient or cost-effective transmission facilities, capturing currently missed opportunities and achieving economies of scale.[370] North Carolina Commission and Staff argue that Long-Term Regional Transmission Planning can provide state utility commissions and consumer advocates with useful information to promote a cost-effective and reliable transmission grid.[371]

148. NextEra states that Long-Term Regional Transmission Planning can minimize overall costs to consumers by enabling the lowest-cost generation.[372] Relatedly, Tabors Caramanis Rudkevich states that the NOPR proposal would establish a transmission planning process that coordinates across franchises, states, and regions, which will reduce the production cost of delivery of energy to consumers.[373]

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[369] DC and MD Offices of People's Counsel Initial Comments at 8-10 (citing Patrick Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115, 115-134 (2020), https://www.sciencedirect.com/science/article/pii/S2542435120305572?dgcid=author%20_blank); *see also* EEI Supplemental Comments at 1 (arguing that robust transmission development will provide cost savings from greater access to low-cost resources).

[370] *See* AEP Initial Comments at 8-12.

[371] North Carolina Commission and Staff Initial Comments at 4.

[372] NextEra Initial Comments at 62.

[373] Tabors Caramanis Rudkevich Initial Comments at 4-5.

149. PPL notes that Long-Term Regional Transmission Planning may improve some of the limitations of criteria-based transmission planning, which is currently employed in RTOs/ISOs.[374] Ørsted supports the proposed requirements regarding Long-Term Regional Transmission Planning and argues that existing regional transmission plans fail to anticipate the size and scale of future offshore wind generation development, leading to inaccurate plans and insufficient investment in infrastructure needed to integrate known future offshore wind generation.[375]

150. State Agencies assert that the Commission's various proposed reforms in the NOPR collectively would enhance transparency, prevent unnecessary investment in local transmission projects, and improve the competitive landscape.[376] US DOJ and FTC support reforms that address obstacles to transmission development and that are implemented consistent with principles for competition.[377]

**b. Requests for Flexibility in Transmission Planning**

151. A number of commenters support the Commission's proposal to require Long-Term Regional Transmission Planning, but also express reservations or objections regarding what they perceive as an overly prescriptive approach that may disrupt existing

[374] PPL Initial Comments at 4. PPL claims that, while PJM may perform long-term transmission planning on a 15-year time frame on paper, its long-term transmission planning is effectively undertaken over only 7 to 10 years. *Id.*

[375] Ørsted Initial Comments at 4-5.

[376] State Agencies Reply Comments at 6.

[377] US DOJ and FTC Initial Comments at 19.

processes that are already working.[378] For example, multiple commenters express concerns that the NOPR's allegedly prescriptive requirements for Long-Term Regional Transmission Planning will significantly limit needed discretion to conduct such planning, and that, without discretion to adjust the scenario modeling and assumptions to regional circumstances, the final rule could lead to more delay and conflict.[379] MISO TOs contend that the NOPR proposals vary sufficiently from MISO's current approach that MISO and its stakeholders will need to engage in complex and time-intensive revisions in order to comply.[380] Similarly, City of New Orleans Council asks that the final rule not hinder existing MISO processes.[381]

152. Multiple commenters recommend that the Commission's final rule establish principles and objectives for long-term transmission planning that address the Commission's concerns and provide transmission providers with the flexibility to develop tailored long-term transmission planning approaches and implementation details

[378] *See, e.g.*, Avangrid Initial Comments at 6, 9; CAISO Initial Comments at 1-2, 7-10, 13; California Commission Initial Comments at 6; Duke Initial Comments at 1-2; Indiana Commission Initial Comments at 1, 3; ISO-NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4-5 (citing NOPR, 179 FERC ¶ 61,028 at PP 66, 104); Massachusetts Attorney General Initial Comments at 10-12; Michigan Commission Initial Comments at 4-5; MISO Initial Comments at 23; NEPOOL Initial Comments at 7; NYISO Initial Comments at 11; PG&E Initial Comments at 2; PJM Initial Comments at 54-55; US Chamber of Commerce at 4-5.

[379] Ameren Initial Comments at 8; ISO-NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8-9; MISO TOs Reply Comments at 10-12.

[380] MISO TOs Reply Comments at 10-11.

[381] City of New Orleans Initial Comments at 5-6.

accordingly.[382] MISO recommends that each transmission provider should give the Commission a report outlining the actions and processes that support the Commission's principles and guidance, and then the Commission could direct specific changes within each transmission planning region as it deems necessary.[383]

153. Multiple commenters argue for flexibility to accommodate local and regional differences, including differences in public policy goals that affect transmission planning.[384] NYISO asks that the final rule give each transmission planning region discretion to determine, in coordination with state entities and stakeholders, how best to incorporate the Long-Term Regional Transmission Planning requirements within its transmission planning framework.[385] California Municipal Utilities add that a significant amount of demand in the West is served by publicly-owned utilities and electric

[382] ISO-NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4-5, 8-9; MISO Initial Comments at 22-23.

[383] MISO Initial Comments at 22.

[384] APPA Reply Comments at 9-10; California Commission Initial Comments at 5; California Municipal Utilities Reply Comments at 2-4; Industrial Customers Reply Comments at 4; Louisiana Commission Reply Comments at 4-5; Georgia Commission Initial Comments at 2; NARUC Initial Comments at 3; New York Transco Initial Comments at 5; North Dakota Commission Initial Comments at 3; New York Commission and NYSERDA Initial Comments at 3; OMS Initial Comments at 3; PJM States Initial Comments at 2.

[385] NYISO Initial Comments at 13.

cooperatives, which fall outside of state commission regulation, highlighting the need for flexibility in planning.[386]

154. Dominion asserts that any reforms adopted in this proceeding should align with the purpose of the transmission system, which is to provide reliable, affordable electric service to customers rather than to benefit generators.[387]

155. APPA agrees with concerns expressed by Commissioner Christie and former Commissioner Danly that overly prescriptive transmission planning requirements have the potential to interfere with existing regional transmission planning processes, and hence argues that adequate flexibility is needed.[388] Mississippi Commission states that where an RTO/ISO or non-RTO/ISO transmission provider is already engaged in long-term regional transmission planning, the Commission should accept flexibility and regional variations on compliance to address region-specific issues, including the delineation of regional and local transmission facilities through, for example, a voltage threshold (e.g., 100 kV).[389]

[386] California Municipal Utilities Reply Comments at 2.

[387] Dominion Initial Comments at 5.

[388] APPA Initial Comments at 23.

[389] Mississippi Commission Reply Comments at 7-8 (citing Entergy Initial Comments at 2-4; Louisiana Commission Initial Comments at 35-36; Michigan State Entities Initial Comments at 2; MISO Initial Comments at 2-3, 19; MISO TOs Initial Comments at 2, 4, 13-15).

156. CAISO maintains that the Commission should allow it to continue evaluating transmission needs driven by Public Policy Requirements in its transmission planning process, in addition to any Long-Term Regional Transmission Planning process, and give CAISO the flexibility to continue using resource portfolios and geographic zones identified by state agencies and local regulatory authorities.[390] Although ACORE urges the Commission not to grant requests for less stringent transmission planning requirements in the final rule, ACORE agrees that there may be cases where an individual RTO's/ISO's existing processes may be superior to the proposed reforms, such as in the case of CAISO's treatment of public policy projects within its annual transmission planning process.[391] California Municipal Utilities note that CAISO has already begun to implement some of the key reforms that the Commission proposed in the NOPR, specifically by adopting a 20-year outlook for transmission planning.[392]

157. MISO requests that a final rule support, rather than detract from, its demonstrated success in long-term transmission planning.[393] MISO TOs request that the Commission revise the NOPR's required parameters for Long-Term Regional Transmission Planning to accommodate the robust long-term regional transmission planning that some

[390] CAISO Reply Comments at 17-18.

[391] ACORE Reply Comments at 4.

[392] California Municipal Utilities Initial Comments at 5.

[393] MISO Reply Comments at 2-3.

transmission planning regions, like MISO, have already developed.[394] Similarly, Ameren contends that the Commission should find that MISO's approved Long Range Transmission Planning process substantially complies with the proposed reforms.[395]

158. New York TOs support allowing transmission planning regions with already successful transmission planning processes to retain those processes while making incremental enhancements and to demonstrate on compliance that they meet the NOPR's objectives.[396] New York Transco asserts that the current NYISO public policy transmission planning processes already address, at least in part, the proposed reforms and believes that the Commission should permit regional flexibility.[397]

159. SPP states that its current transmission planning processes are sufficient to meet the intent of the Commission's proposed Long-Term Regional Transmission Planning reforms.[398] Omaha Public Power states that SPP and other RTOs/ISOs have already developed long-term planning scenarios and suggests that transmission providers that already have long-term planning scenarios should be provided with the flexibility to continue using their previously established processes.[399]

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[394] MISO TOs Reply Comments at 11-12.

[395] Ameren Initial Comments at 8.

[396] New York TOs Initial Comments at 8-9.

[397] New York Transco Initial Comments at 5.

[398] SPP Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 3).

[399] Omaha Public Power Initial Comments at 4.

160. In contrast, some commenters argue that the final rule should not provide too much flexibility to transmission providers because that flexibility will undermine Long-Term Regional Transmission Planning.[400] Many commenters opposing greater flexibility argue that the Commission should establish minimum requirements for Long-Term Regional Transmission Planning.[401]

161. AEP argues that the Commission must resist requests for excessive regional flexibility that could threaten the development of long-term regional transmission and only permit it in limited instances that exceed minimum requirements.[402] Onward Energy states that, while flexibility is reasonable, the Commission must clearly identify who will drive regional transmission planning processes and how transmission planners will coordinate, study, and implement Long-Term Scenarios that represent realistic future resource portfolios.[403] Clean Energy Associations state that without robust and proactive transmission planning rules, the Commission cannot determine that rates remain just and

[400] *See, e.g.*, ACORE Reply Comments at 2-4 (citing New Jersey Commission Initial Comments at 7); AEP Reply Comments at 2-5; Clean Energy Associations Reply Comments at 4-6; DC and MD Offices of People's Counsel Reply Comments at 2-3; Hannon Armstrong Reply Comments at 1; Interwest Reply Comments at 3-4; Invenergy Reply Comments at 8-10; PIOs Reply Comments at 5-6.

[401] *See, e.g.*, AEE Reply Comments at 9-13, 16-18, 21-22; AEP Reply Comments at 2-5; Cypress Creek Reply Comments at 4-9; Interwest Reply Comments at 3-4; Invenergy Initial Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 2; PIOs Reply Comments at 2-3; SEIA Reply Comments at 1-3; Southeast PIOs Reply Comments at 21-22; SREA Reply Comments at 26-27.

[402] AEP Reply Comments at 3.

[403] Onward Energy Initial Comments at 4.

reasonable.[404] DC and MD Offices of People's Counsel state that, while regional flexibility is critical, long-term transmission planning rules that provide carve-outs and opt-outs will result in balkanized transmission development.[405]

162. Hannon Armstrong states that by diluting the proposed requirements or granting flexibility as some commenters request, the Commission would allow existing deficiencies to persist, enabling the continued reliance on either the generator interconnection process or operational planning to resolve or mitigate constraints.[406] Invenergy rebuts commenters' claims that the NOPR is too prescriptive or that some of the NOPR requirements should be optional, stating that optional processes and deference to regional flexibility will not ensure needed transmission is built and that a flexible approach has already been tried and has failed to produce sufficient results.[407]

### c. Comments Regarding More Comprehensive Transmission Planning

163. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and should not supplant existing shorter-term transmission

[404] Clean Energy Associations Reply Comments at 4-5 (citing CAISO Initial Comments at 3; California Commission Initial Comments at 11; ISO-New England Initial Comments at 4; ISO/RTO Council Initial Comments at 8; NYISO Initial Comments at 3; PG&E Initial Comments at 4; PJM States Initial Comments at 4).

[405] DC and MD Offices of People's Counsel Reply Comments at 2.

[406] Hannon Armstrong Reply Comments at 1.

[407] Invenergy Reply Comments at 9-10.

planning processes.[408] PJM asks the Commission to confirm that it did not mean for the NOPR proposals on Long-Term Regional Transmission Planning to modify the existing reliability and market efficiency transmission planning processes.[409] Transmission Dependent Utilities encourage the Commission to ensure that transmission providers do not focus on long-term objectives to satisfy state renewable energy portfolio requirements to the detriment of near-term reliability needs, such as end-of-life transmission planning.[410] Large Public Power and NEPOOL state that any final rule should clearly state that the current near-term transmission planning rules and processes, especially cost allocation, are not changed by the final rule's reforms, except where expressly indicated.[411] Ameren argues that the Commission was clear that changes to existing reliability and economic transmission planning requirements are beyond the scope of the

[408] Ameren Reply Comments at 17; CAISO Initial Comments at 2-3, 17-20; Chemistry Council Initial Comments at 5; Dominion Initial Comments at 23; Exelon Initial Comments at 6-7; Indicated PJM TOs Initial Comments at 12; ITC Initial Comments at 8-9; Large Public Power Initial Comments at 14-16; NEPOOL Initial Comments at 8; NESCOE Initial Comments at 21-23; PJM Initial Comments at 55-57; PPL Initial Comments at 4-5; Transmission Dependent Utilities Initial Comments at 4-6; WIRES Initial Comments at 6-7; Xcel Initial Comments at 16.

[409] PJM Initial Comments at 55-57.

[410] Transmission Dependent Utilities Initial Comments at 4-6.

[411] Large Public Power Initial Comments at 16-18; NEPOOL Initial Comments at 7-8.

NOPR and that the comments filed supporting holistic planning have provided no compelling basis for the Commission to address them.[412]

164. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and must not supplant existing shorter-term transmission planning processes for transmission needs driven by Public Policy Requirements.[413] CAISO states that the NOPR provides no guidance or criteria regarding how a transmission provider can demonstrate that its existing process for addressing transmission needs driven by Public Policy Requirements does not interfere with or undermine Long-Term Regional Transmission Planning. CAISO contends that it should not have to re-justify its existing process or demonstrate that its existing process is consistent with or superior to Long-Term Regional Transmission Planning.[414]

165. AEP asserts that transmission providers should look at nearer-term reliability and economic transmission planning processes to determine whether there are needs that can be incorporated into Long-Term Regional Transmission Planning and addressed by a Long-Term Regional Transmission Facility.[415] SEIA recommends that the Commission require transmission providers to engage in portfolio-based transmission planning that

[412] Ameren Reply Comments at 17.

[413] Anbaric Initial Comments at 22-27; CAISO Initial Comments at 2-3, 9-20; Large Public Power Initial Comments at 14-16.

[414] CAISO Initial Comments at 19.

[415] AEP Initial Comments at 10.

integrates all relevant factors, including near-term needs, into Long-Term Regional Transmission Planning.[416] Policy Integrity argues that inclusion of specific requirements for transmission modeling are needed to fulfill the mandate of ensuring wholesale electric rates are just and reasonable.[417] Xcel recommends that the Commission require that known or expected generation be included in short-term regional transmission planning assumptions.[418]

166. PIOs state that, if the two processes continue to exist, the Commission should mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process. Otherwise, PIOs contend, inconsistent assumptions between the two processes could lead to redundant transmission projects and failure to identify more efficient solutions. In particular, PIOs argue, if an Order No. 1000 transmission planning process base case identifies transmission needs that are not anticipated in the Long-Term Scenarios, the opportunities for more efficient planning created by the long-term process will be lost. In addition, PIOs suggest that there may be opportunities for stakeholders to undermine Long-Term Regional Transmission Planning if they believe Order No. 1000 transmission planning would produce more favorable results for them. PIOs further argue that because uncertainty grows the further one looks into the future,

[416] SEIA Initial Comments at 20-21.

[417] Policy Integrity Supplemental Comments at 3.

[418] Xcel Initial Comments at 16.

there should not be significant differences in the short-term results of Long-Term Regional Transmission Planning and Order No. 1000 regional transmission planning processes.[419]

167. Several commenters support forward-looking, Long-Term Regional Transmission Planning but argue for holistic planning using multiple drivers of transmission needs.[420] They argue that a holistic approach is more efficient, better accounts for long-term benefits of new transmission, addresses the needs of more stakeholders, and is more likely to support development of regional transmission facilities, among other benefits. Competition Advocates support a final rule that reflects the benefits of holistic modeling,[421] while New Jersey Commission contends that holistic transmission planning using a competitive process provides significant benefits, including reducing costs.[422]

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[419] PIOs Initial Comments at 44-46.

[420] *See, e.g.*, Acadia Center and CLF Initial Comments at 4-7; ACEG Initial Comments at 6-7, 30-31; ACORE Initial Comments at 5-7; Anbaric Initial Comments at 5-10; AEE Reply Comments at 2; Business Council for Sustainable Energy Initial Comments at 2; City of New York Initial Comments at 4-6; Competition Coalition Initial Comments at 15-16; Cypress Creek Reply Comments at 4-5; Enel Initial Comments at 3; Pine Gate Initial Comments at 18-19; PIOs Reply Comments at 11; SEIA Reply Comments at 2, 7-8; *see also* Pattern Energy Initial Comments at 16.

[421] Competition Advocates Supplemental Comments at 1; *see also* Policy Integrity Supplemental Comments at 2-3 (citing Jennifer Danis *et al.*, Inst. for Policy Integrity, *Transmission Planning for the Energy Transition: Rethinking Modeling Approaches* (Dec. 2023), https://policyintegrity.org/files/publications/Transmission_Report_2023.pdf).

[422] New Jersey Commission Motion to Lodge at 4-5 (citing *In re Declaring Transmission to Support Offshore Wind a Pub. Policy of the State of N.J.*, Order on the State Agreement Approach SAA Proposals, N.J. BPU Docket No. QO20100630 (Oct. 26, 2022),

168. To ensure that reforms are not undermined by existing processes, Clean Energy Buyers recommend that the Commission extend to all existing regional transmission planning processes—not just transmission planning processes to address transmission needs driven by Public Policy Requirements, as proposed in the NOPR—the requirement that, on compliance with any final rule, transmission providers who seek to retain existing regional transmission planning and cost allocation processes must demonstrate that continued use of those processes does not interfere with or undermine Long-Term Regional Transmission Planning.[423]

169. However, other commenters support the Commission's proposal in the NOPR to *not* apply the proposed reforms to existing Order No. 1000 reliability and near-term economic regional transmission planning processes.[424] Ohio Consumers support the NOPR's proposal to mostly retain the regional transmission planning processes outlined in Order No. 1000, explaining that PJM stakeholders have reached an effective settlement

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https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279919; Johannes P. Pfeifenberger, et al., Brattle Grp., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report*, (Oct. 26, 2022), https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279916; PJM, *Economic Analysis Report: 2021 SAA Proposal Window to Support NJ OSW* (Nov. 4, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221104-special/informationalonly---njosw-economic-analysis-report.ashx).

[423] Clean Energy Buyers Initial Comments at 9-10.

[424] Ameren Reply Comments at 17; Exelon Initial Comments at 6-7; ITC Initial Comments at 8-9; WIRES Initial Comments at 6-7.

under that framework in which costs are allocated in a manner that is roughly commensurate with the benefits received.[425]

170. Some commenters argue that the Commission should require that local transmission projects be evaluated and approved as part of a holistic planning approach.[426] AEE asserts that, to ensure that transmission providers consider the full range of needs in developing long-term regional transmission plans, the final rule should require them to consider local transmission plans and to determine whether a regional solution would be more efficient or cost-effective.[427] OMS suggests that the Commission require that all local transmission projects be evaluated and approved as part of regional transmission planning processes with the opportunity for meaningful input from retail regulators, which it argues will enable participation by state regulators while respecting transmission owners' abilities to maintain their systems.[428]

171. By contrast, WIRES argues that the Commission should maintain the distinction between regional transmission planning and local transmission planning. WIRES argues that, while the regional transmission planning process is directed toward addressing certain reliability concerns, economic criteria, and public policy initiatives, it is not

[425] Ohio Consumers Initial Comments at 7 (citing NOPR, 179 FERC ¶ 61,028 at P 72).

[426] AEE Initial Comments at 3, 38; OMS Initial Comments at 16-17; LS Power and NRG Supplemental Comments at 34-37.

[427] AEE Initial Comments at 3, 38.

[428] OMS Initial Comments at 16-17.

geared toward addressing additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that is typically the focus of local transmission planning.[429] Similarly, AEP states that if an RTO/ISO were to make all decisions regarding local transmission projects, they would also need to assume the accompanying responsibility—and the liability—for such decisions, which would entail physical inspection and condition assessment of assets, as well as a determination of when transmission facilities have reached their end of useful life.[430] AEP points out that both CAISO and PJM have expressly stated that they do not wish to undertake these types of activities and assume such obligations.[431]

**d. Concerns Regarding Favoring Renewable Resources**

172. ELCON argues that the Commission's proposal could require customers to pay higher costs to connect distant renewables when a lower-cost transmission project would provide the same reliability or economic benefits.[432] Utah Division of Public Utilities states that Long-Term Scenario requirements favoring renewable generation burden transmission providers while providing little to no benefit and that developers and generation utilities should determine which renewable generation should be developed at

[429] WIRES Initial Comments at 9.

[430] AEP Reply Comments at 7.

[431] *Id.* (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160, at P 18 (2018); PJM Interconnection, L.L.C., Comments of PJM, Docket No. ER20-2308-000, at attach. A (July 2, 2020) (citation omitted)).

[432] ELCON Initial Comments at 9-10.

their respective zones or sites.[433] Utah Commission further contends that nationwide mandates for transmission planning add costs, produce confusion, and create conflicts that could lead to higher utility prices for consumers.[434] Kansas Ratepayer Advocates contend that Long-Term Regional Transmission Planning would presume material additions of renewable energy to serve consumers within a state, coupled with material additions of transmission to interconnect those renewables to the electric transmission grid, which do not reflect the unique circumstances of Kansas.[435]

173. Vistra asserts that the proposed reforms could devolve into the subsidization of resources chosen to achieve state policy goals, masking the true costs of those remotely located resources that require extensive transmission development to interconnect to the grid and leading to market distortions that undermine the objectives of these reforms.[436]

174. Louisiana Commission states that the NOPR would result in subsidization of the costs of transmitting remote renewable energy, spreading the costs out broadly based on an expanded "nebulous concept of 'benefits' and perceived 'public policy,'" thus ensuring that those transmission projects will pass any economic test.[437] According to

[433] Utah Division of Public Utilities Initial Comments at 7-8.

[434] Utah Commission Initial Comments at 11, 13.

[435] Kansas Ratepayers Advocates Reply Comments at 2.

[436] Vistra Initial Comments at 11.

[437] Louisiana Commission Reply Comments at 12 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 2)).

Louisiana Commission, this subsidization would interfere with price signals, thereby distorting the efficient functioning of the wholesale market.[438] Louisiana Commission states that any Commission policy should be resource and technology neutral and should not impose costs on states that do not benefit from distant renewable power.[439]

175. Finally, Louisiana Commission contends that the NOPR's long-term transmission planning requirements could threaten the reliability of the transmission grid because the intermittent renewable resources that the NOPR favors do not provide stable output and are not dispatchable.[440] Similarly, former Kansas Commission Chair Keen argues that the NOPR fails to acknowledge the reliability concerns associated with a generation mix that is too heavily weighted to intermittent renewable generation resources.[441]

#### e. Concerns Regarding Uncertainty, Over-building, and Costs

176. A few commenters argue that long-term transmission planning introduces uncertainty or incentivizes speculative transmission development.[442] While EPSA acknowledges that long-term forecasts can provide valuable information about the

[438] Louisiana Commission Initial Comments at 19-21.

[439] *Id.* at 21-24.

[440] *Id.* at 21-23. *But see* Cypress Creek Reply Comments at 2-4 (disagreeing with Louisiana Commission and claiming that regionally coordinated transmission planning should provide demonstrable system reliability benefits).

[441] Kansas Commission Chair Keen Initial Comments at 1.

[442] EPSA Initial Comments at 7; New England Systems Initial Comments at 22; *see also* NRECA Initial Comments at 28-29.

potential scale of construction necessary to achieve decarbonization, it argues that using such forecasts to justify investment shifts the risks to consumers from developers and facility owners.[443] California Municipal Utilities state that, as transmission planning horizons are extended, the changes in resource mix, technology types, the location of resources, and demand will likely change congestion patterns and therefore the need for transmission upgrades needed to address them.[444]

177. Louisiana Commission states that it opposes the NOPR proposal because it would lead to an inefficient and expensive build-out of the transmission system and could be used to justify shifting the costs of this build-out to load.[445] ELCON states that it is concerned that the Commission's proposal to prioritize Long-Term Regional Transmission Planning to connect renewable generation over Long-Term Regional Transmission Planning for economically necessary transmission may exceed the Commission's authority if it increases transmission rates for the benefit of a few stakeholders.[446] Southern states that transmission expansion predicated on hypothetical resources that might not materialize would not satisfy the fundamental legal requirements of being used and useful, prudent, and/or otherwise needed for the public use, could harm

[443] EPSA Initial Comments at 7.

[444] California Municipal Utilities Initial Comments at 7.

[445] Louisiana Commission Initial Comments at 4-5.

[446] ELCON Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 (Danly, Comm'r, dissenting, at P 2 n.3); NOPR, 179 FERC ¶ 61,028 at P 47).

reliability, and would violate the Commission's duty under the FPA to facilitate transmission planning to meet load-serving entities' obligations.[447]

178. Industrial Customers argue that the NOPR does not provide evidence that extending the transmission planning horizon would exclude modeling of speculative projects, which would likely result in the over-building of transmission and unnecessary increases in rates.[448] Industrial Customers cite the D.C. Circuit's finding in *Old Dominion Electric Cooperative v. FERC* that "[w]e are sensitive to the concern . . . that individual utilities should not have free rein to impose unjustified costs on an entire region by unilaterally adopting overly ambitious planning criteria," and argue that the current NOPR proposal would result in the same issues.[449]

179. NRG urges caution on over-reliance on any 20-year planning study for making transmission investments due to the inherent uncertainty of a study with such a long planning horizon.[450] NRG argues that the NOPR will increase delivery costs by reducing the value of private investments and replacing such investments with a centrally planned, cost-socialized approach that is founded on at least some incorrect assumptions.[451] NRG

[447] Southern Initial Comments at 32, 34.

[448] Industrial Customers Initial Comments at 6, 15-16, 19-21.

[449] *Id.* at 16 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1263 (D.C. Cir. 2018)).

[450] NRG Initial Comments at 8.

[451] *Id.* at 3.

provides several examples of how forecast errors have caused adverse consequences, including forecasts of natural gas prices, load forecasts, and canceled planned transmission facilities.[452]

180. Likewise, Ohio Consumers urge the Commission to avoid adopting proposals based on long-term projections that justify massive charges to consumers based on hypothetical scenarios.[453] Ohio Consumers state that Ohio customers have recently been saddled with rate increases in part due to transmission investments and that long-term transmission planning requirements would increase ratepayer burden, which is especially troublesome if projections turn out to be inaccurate.[454]

181. As an alternative to Long-Term Regional Transmission Planning, Potomac Economics states that the Commission could require the transmission planning process to incorporate a broader array of near-term emerging trends that are less uncertain than the proposed longer-term factors.[455] Louisiana Commission states that it shares Potomac Economics' concerns. Louisiana Commission urges the Commission to heed testimony submitted by Potomac Economics arguing that: (1) there is significant uncertainty about future technology and a significant risk of investing in transmission projects that will not ultimately provide value; (2) large transmission projects are often not the most economic,

[452] *Id.* at 10-11.

[453] Ohio Consumers Initial Comments at 5.

[454] *Id.*

[455] Potomac Economics Initial Comments at 4.

whereas smaller, targeted projects are more beneficial; and (3) there can and likely would be stranded transmission if transmission planning processes attempt to identify and meet transmission needs 20 to 30 years in the future.[456]

182. US Chamber of Commerce argues that the Commission should ensure that any Long-Term Regional Transmission Planning reforms do not perpetuate an irrational transmission buildout that undermines competitive advantages of domestic electricity rates. US Chamber of Commerce asserts that the loss of competitive advantage would lead to lost jobs, lost economic growth, decreased electricity use, and fixed system costs assessed to fewer customers.[457]

183. Vistra states that the proposed reforms lean toward accounting for regulatory and public policy initiatives that may shape changes in the generation mix without sufficiently incorporating the commercial and markets-related aspects of generation development.[458] Vistra states that, without a process to assess commercial interest and financial commitment from generation developers, long-term regional transmission plans may under- or over-build transmission facilities or build them in the wrong locations.[459] Relatedly, NRECA states that planning a regional transmission network for generation resources or changes in demand not identified by load-serving entities' forecasts, and

[456] Louisiana Commission Reply Comments at 13-14.

[457] US Chamber of Commerce Initial Comments at 8.

[458] Vistra Initial Comments at 7.

[459] *Id.*

instead through unsupported top-down assumptions, may produce uneconomic results from over-building and increase reliability risks.[460]

184. NRG states that, in light of the uncertainty of variables such as the amount of electrification and resulting load requirements, technology costs for new resources, and viability and repurposing of existing resources, it is not clear whether a "no regrets" option genuinely exists. NRG also asserts that the centralized planning envisioned in the NOPR sacrifices the ability of market participants to use available information to assess whether their investments will be viable in the future, which is a critical feature of competition. NRG asserts that the Commission has not contemplated that trade-off or quantified its costs, noting that past long-term transmission planning studies have done a questionable job at forecasting future needs.[461]

185. Other commenters, however, note that the NOPR proposal includes measures that mitigate the uncertainty inherent in longer-term regional transmission planning.[462] For example, New Jersey Commission states that the proposed requirements to develop multiple scenarios and perform reassessments mitigates the uncertainty inherently present in a 20-year transmission planning horizon.[463] Additionally, several commenters rebut

[460] NRECA Initial Comments at 18-19.

[461] NRG Initial Comments at 8.

[462] New Jersey Commission Initial Comments at 10-11; PIOs Initial Comments at 15-16.

[463] New Jersey Commission Initial Comments at 10-11.

opposition to Long-Term Regional Transmission Planning based on concerns that it presents unreasonable levels of uncertainty.[464] For example, SREA and Clean Energy Buyers assert that periodic updates of forecasts and scenarios will help to mitigate uncertainty.[465]

186. Policy Integrity further explains that future uncertainty is exactly why long-term scenario planning is necessary to ensure just and reasonable rates. Policy Integrity states that the current transmission planning process uses deterministic modeling that does not account for the changing world, which will not lead to the development of efficient or cost-effective transmission solutions. Policy Integrity asserts that, in contrast, long-term scenario planning will allow transmission planners to be prepared for changes.[466] Policy Integrity argues that any forward-looking decision will have a degree of uncertainty, but that the risk posed by uncertainty can be mitigated and managed by using a portfolio evaluation of costs and benefits.[467] Policy Integrity further argues that ignoring the uncertainty surrounding the energy transition runs its own risk of failing to build transmission that can be useful to meet needs in the short, medium, and long term.[468]

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[464] Clean Energy Buyers Reply Comments at 8; Policy Integrity Reply Comments at 2; SREA Reply Comments at 21-24.

[465] Clean Energy Buyers Reply Comments at 8; SREA Reply Comments at 23.

[466] Policy Integrity Reply Comments at 2.

[467] *Id.* at 3-4.

[468] *Id.* at 4.

### f. Concerns Regarding Incentives for Resource Development

187. Vistra asserts that it is critical for Commission policy to maintain interconnection cost signals to drive cost-effective generation siting choices.[469] Vistra also argues that a policy that assigns all interconnection-related network upgrade costs, or even a disproportionately high share, to load undermines the incentive that generation developers currently have to site new projects in locations that minimize the related transmission upgrade costs.[470]

188. In contrast, New Jersey Commission argues that requiring individual interconnecting generators to pay for piecemeal interconnection-related network upgrades does not necessarily encourage developers to make siting decisions that minimize the overall cost of integrating large amounts of new generation.[471] Likewise, Clean Energy Associations state that robust, proactive regional transmission planning will better incent efficient siting decisions, because generators will evaluate the likely costs of interconnection facilities that ensure deliverability to the grid, rather than more broadly beneficial transmission facilities.[472]

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[469] Vistra Initial Comments at 7.

[470] *Id.* at 7-8.

[471] New Jersey Commission Reply Comments at 7.

[472] Clean Energy Associations Reply Comments at 9 (citing ACEG 2021 Interconnection Report at 15).

### g. Comments Regarding Definition of Long-Term Regional Transmission Facility

189. PJM states that the Commission should clarify certain details of the NOPR proposal, including the meaning of the word "identified" in the proposed definition of Long-Term Regional Transmission Facility.[473] In addition, PJM requests that the Commission clarify that if a transmission project shows up in several Long-Term Scenarios but is not selected until it reaches one of the shorter-term reliability and market efficiency transmission planning processes, that project would not be considered a Long-Term Regional Transmission Facility for selection and cost allocation purposes.[474] Otherwise, PJM contends, the rules for selection and cost allocation for transmission projects selected in the shorter-term and intermediate-term reliability and market efficiency transmission planning processes will be unclear, leading to re-litigation.[475]

### h. Challenges to Commission Jurisdiction or Authority

#### i. FPA section 201

190. Some commenters argue that the NOPR proposals exceed the Commission's jurisdiction or that the Commission otherwise lacks the authority to adopt a final rule in this proceeding. Of these commenters, most contend that the NOPR proposal interferes with authority reserved to the states under FPA section 201.[476]

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[473] PJM Initial Comments at 8, 98.

[474] *Id.* at 99.

[475] *Id.* at 99, 101.

[476] Alabama Commission Initial Comments at 3-4, 7-8; Kansas Ratepayer Advocates Reply Comments at 2-3; Louisiana Commission Initial Comments at 5, 8-9,

191. Some commenters argue that the NOPR proposal intrudes on the authority reserved to the states under FPA section 201 over integrated resource planning processes or resource mix decision making.[477] For example, Alabama Commission states that the NOPR proposal for Long-Term Regional Transmission Planning would intrude on state integrated resource planning to the extent that it dictates the construction of facilities through a top-down regional process or seeks to influence or mandate a substantive change to the generation resource mix.[478] Similarly, Nevada Commission argues that the NOPR may impact states' authority to determine their own mix of generating resources. Nevada Commission contends that the NOPR may cross the line from regulating interstate transmission to regulating intrastate processes—particularly because the Commission has not asserted jurisdiction over bundled retail transmission.[479] Louisiana

27-28; Louisiana Commission Reply Comments at 14-15; Mississippi Commission Initial Comments at 3, 5-6; Mississippi Commission Reply Comments at 2; Nevada Commission Initial Comments at 2-3, 6; SERTP Sponsors Initial Comments at 5, 15-19 & n.20; SERTP Sponsors Reply Comments at 12-13; Southern Initial Comments at 3-8, 12-13, 15-24; Southern Reply Comments at 3, 6-7; Utah Commission Initial Comments at 7-9; Undersigned States Reply Comments at 2, 4-5.

[477] Alabama Commission Initial Comments at 3-4, 7-8; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8-9, 27-28; Louisiana Commission Reply Comments at 14-15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)); Nevada Commission Initial Comments at 2-3; SERTP Sponsors Initial Comments at 5, 15-19 & n.20; SERTP Sponsors Reply Comments at 12-13; Southern Initial Comments at 3-8, 12-13, 15-24; Southern Reply Comments at 3, 6-7; Utah Commission Initial Comments at 7-9; Undersigned States Reply Comments at 2, 4-5.

[478] Alabama Commission Initial Comments at 3-4, 7-8.

[479] Nevada Commission Initial Comments at 2-3.

Commission argues that the Commission should not override state jurisdiction on resource planning, fuel type, and siting decisions, along with the regulation of retail rates.[480]

192. Mississippi Commission requests that the Commission acknowledge that it cannot force regional planning entities to indirectly act as a national integrated resource planner.[481] SERTP Sponsors and Southern argue that the NOPR essentially constitutes a Commission-regulated integrated resource plan/request for proposal process and that, to be workable, Long-Term Regional Transmission Planning instead must be based on state commission-regulated integrated resource planning/request for proposal decisions.[482] SERTP Sponsors and Southern contend that the NOPR proposed to require transmission providers to make independent resource and load decisions because: (1) state integrated resource plans are just one of many factors to be considered in developing Long-Term Scenarios; and (2) state integrated resource planning or request for proposal processes generally use a 10-year planning horizon such that there are no state-approved resources for the second half of the NOPR's proposed 20-year transmission planning horizon.[483]

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[480] Louisiana Commission Initial Comments at 27-28; Louisiana Commission Reply Comments at 14-15.

[481] Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)).

[482] SERTP Sponsors Initial Comments at 15-16; SERTP Sponsors Reply Comments at 12-13; Southern Initial Comments at 4-5, 7, 15-16; Southern Reply Comments at 6-7.

[483] SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 12-13.

SERTP Sponsors and Southern further argue that, in upholding Order No. 1000, the D.C. Circuit emphasized that the Commission was regulating the transmission planning process and not mandating any particular outcome, and that, if the Commission prescribes a process that supplants state decision making, it will have crossed the line into prescribing substantive outcomes and thus exceeded its jurisdiction.[484]

193. Ohio Commission Federal Advocate contends that the NOPR appears designed to target the achievement of narrow environmental policy objectives or the socialization of transmission costs, not to ensure reliability or foster just and reasonable rates.[485] Southern and Utah Commission state that the Commission has consistently recognized that the FPA does not allow the Commission to pick winners and losers when it comes to generation and argue that the Commission has no authority to favor one generation mix over another.[486] Similarly, Louisiana Commission, Kansas Ratepayer Advocates, and Undersigned States contend that the Commission lacks the statutory authority to dictate states' generation resource decisions. They argue instead that each state possesses such authority and is uniquely qualified to choose the generation resources that are needed to economically meet ratepayers' electric service needs within their states.[487]

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[484] SERTP Sponsors Initial Comments at 19; Southern Initial Comments at 23-24 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

[485] Ohio Commission Federal Advocate Initial Comments at 4-6.

[486] Southern Initial Comments at 23 (citing *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 26 (2018)); Utah Commission Initial Comments at 7-9.

[487] Louisiana Commission Initial Comments at 8-10 (citing *Monongahela Power Co.*, 40 FERC ¶ 61,256, at 61,861 (1987); *Pac. Gas & Elec. Co. v. State Energy Res.*

194. SERTP Sponsors and Southern argue that, even if assumptions about the resource mix included in Long-Term Scenarios do not bind states, requiring transmission providers to develop Long-Term Scenarios that are predicated on particular resource assumptions effectively makes a substantive resource decision because it favors the assumed resource mix over others.[488] SERTP Sponsors and Southern contend that this is akin to the Commission attempting to accomplish indirectly what it could not directly.[489] SERTP Sponsors argue that the Commission should support the exercise of traditional state resource and infrastructure planning authority rather than supplant it.[490] North Carolina Commission and Staff argue that the use of the production cost savings benefit in Long-Term Regional Transmission Planning "could conflict with state-jurisdictional resource decisions."[491]

195. Other commenters disagree with these contentions and argue that the NOPR proposal would not intrude on states' reserved authority over resource mix decision

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*Conservation & Dev. Comm'n*, 461 U.S. 190, 212 (1983)); Kansas Ratepayer Advocates Reply Comments at 2; Undersigned States Reply Comments at 2, 4-5 (citing *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. at 205).

[488] SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 19.

[489] SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 18.

[490] SERTP Sponsors Initial Comments at 17, 19; *see also* Undersigned States Reply Comments at 5, 8 (citing *Am. Gas Ass'n v. FERC*, 912 F.2d 1496, 1510 (D.C. Cir. 1990)).

[491] North Carolina Commission and Staff Initial Comments at 7.

making or integrated resource plan processes.[492] Kentucky Commission Chair Chandler and SEIA argue that the NOPR's stated aim of reforming regional and interregional transmission planning processes does not foreclose states' decision making on generation.[493] ACEG contends that the NOPR does not propose or purport to regulate the electric supply mix and that the Commission is acting squarely within its authority under the FPA's cooperative federalism structure.[494] AEE notes that the Commission included integrated resource planning and utility load-serving planning as a factor driving transmission needs and argues that none of the requirements proposed by the Commission directly conflict with integrated resource planning processes, require that integrated resource planning be conducted on a different timeline, or override resource planning efforts.[495] Likewise, Kentucky Commission Chair Chandler reiterates that Kentucky's integrated resource plans are not driving transmission planning processes in the state. He explains that integrated resource plans/requests for proposals are not the basis for generation investment decisions, but the state's requests for proposals seek generation proposals after the integrated resource planning process is complete and a

[492] ACEG Reply Comments at 15; AEE Reply Comments at 23; New Jersey Commission Reply Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2-3.

[493] Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2-3.

[494] ACEG Reply Comments at 15.

[495] AEE Reply Comments at 23.

need for generation is identified.[496] In response to Alabama Commission's arguments that the NOPR's proposed rules have the potential to encroach on state-jurisdictional integrated resource planning and resource procurement processes overseen by Alabama Commission, SREA contends that Alabama Commission in fact does not have a formal integrated resource planning process upon which the Commission could encroach.[497]

196. New Jersey Commission disagrees with commenters who argue that the Commission intends to impose a preferred resource mix on the nation by overriding state choices and contends that such arguments are "profoundly misconstruing" the nature of the NOPR proposal and what the Commission aims to achieve.[498] Instead, New Jersey Commission argues that Long-Term Regional Transmission Planning would address transmission needs that are being driven by state policies, market decisions, and technological changes, all of which reflect consumer-driven demand for cleaner electricity.[499] New Jersey Commission contends that the NOPR proposal would ensure that transmission needs are reliably met at a total cost that is just and reasonable, which New Jersey Commission argues is required—not precluded—by the FPA.[500]

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[496] Kentucky Commission Chair Chandler Reply Comments at 6.

[497] SREA Reply Comments at 2-3.

[498] New Jersey Commission Reply Comments at 1-2.

[499] *Id.* at 2.

[500] *Id.*

197. Some commenters argue that the NOPR proposal would intrude on authority over siting and construction of transmission facilities that is reserved to the states under FPA section 201.[501] For example, Southern argues that the FPA reserves transmission siting authority to the states and that the final rule should not directly or indirectly interfere with this authority.[502] Alabama Commission argues that Long-Term Regional Transmission Planning would interfere with state authority to the extent it dictates the construction of facilities through a top-down regional process.[503] Kansas Ratepayer Advocates state that the Commission would exceed its authority and violate states' constitutional rights by ordering states to construct interregional transmission facilities with construction costs paid by retail ratepayers in Kansas.[504]

198. Nevada Commission explains that Nevada law governs the issuance of permits to construct transmission facilities, and that such facilities—even where their costs are not intended to be recovered through retail rates—must go through and may not bypass that process in favor of regional transmission planning processes.[505] NARUC contends that state participation in cost allocation for a portfolio of Long-Term Regional Transmission

[501] Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2-3; Southern Initial Comments at 21-22.

[502] Southern Initial Comments at 21-22.

[503] Alabama Commission Initial Comments at 7.

[504] Kansas Ratepayer Advocates Reply Comments at 3.

[505] Nevada Commission Initial Comments at 2-3.

Facilities does not require a state, in its role as a transmission siting authority, to approve any projects within the portfolio.[506]

199. A few commenters argue that the NOPR proposal would intrude on the authority over certain transmission planning allegedly reserved to the states under FPA section 201. For example, Mississippi Commission states that the final rule must respect state jurisdictional authority over planning and approval of transmission facilities used to serve state load.[507] Nevada Commission states that Nevada will continue to plan for transmission through its integrated resource planning process and that the Commission should allow "bottom up" transmission planning, particularly in non-RTO/ISO transmission planning regions.[508]

200. In contrast, other commenters express support for the Commission's role in transmission planning. Ohio Consumers argue that the Commission has authority over transmission planning, even in states like Ohio that allow for retail consumer choice.[509] SREA explains that states and other jurisdictional regulators will continue to have ultimate control over generation resource planning and transmission planning, regardless

[506] NARUC Initial Comments at 29.

[507] Mississippi Commission Initial Comments at 5 (citing Mississippi Commission ANOPR Comments at 2, 17; NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at PP 2, 11-14)).

[508] Nevada Commission Initial Comments at 6.

[509] Ohio Consumers Initial Comments at 26 (citing *New York v. FERC*, 535 U.S.at 23-24, 26-28).

of what a regional transmission body proposes. SREA states that, even within RTO/ISO regions, "transmission or generation resource plans are subject to review, update or even cancellation, and those decisions are always determined by the relevant regulatory bodies."[510] Vistra states that any final rule should recognize the legal and practical boundaries on the Commission's role in transmission development and in shaping the generation sector. According to Vistra, the Commission has successfully relied on its general authority under FPA sections 205 and 206 to oversee rates, terms, and conditions of jurisdictional service as the basis for its policies on transmission planning.[511]

201. Finally, Mississippi Commission argues that the NOPR proposal may infringe upon states' reserved authority under FPA section 201 to make resource adequacy decisions. Mississippi Commission explains that, when an RTO/ISO approves construction to deliver generation output to remote utilities that have failed to agree to purchase the energy, that RTO/ISO infringes on the state's resource adequacy jurisdiction.[512] Mississippi Commission contends that requiring State A to pay for transmission upgrades to rely on energy generated in State B, despite State A having constructed its own generation facilities, would usurp State A's resource adequacy jurisdiction.[513]

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[510] SREA Reply Comments at 1-2.

[511] Vistra Initial Comments at 4 & n.6.

[512] Mississippi Commission Initial Comments at 5-6.

[513] *Id.* at 13.

### ii. "Major Questions Doctrine"

202. Some commenters argue that the NOPR proposal would not withstand judicial review under the major questions doctrine.[514]

203. Louisiana Commission claims that the NOPR proposal violates principles of "agency law" and the separation of powers doctrine because Congress has not clearly delegated to the Commission the authority to enact far-reaching, nationwide policy changes favoring one form of generation over another.[515] Louisiana Commission contends that the NOPR proposals exceed the limits of the FPA, which does not provide clear delegated authority for the Commission to decide types of generating resources. Louisiana Commission argues that the Commission therefore lacks the authority to determine whether the country should undergo a clean energy transition. Drawing parallels between the NOPR proposal and the U.S. Supreme Court's decision in *West Virginia v. EPA*, Louisiana Commission avers that the determination of what type of generating resources should be transmitted from where in the United States qualifies as a "major question" of public policy that Congress should order.[516]

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[514] Louisiana Commission Initial Comments at 6, 12-13; Ohio Consumers Reply Comments at 14; SERTP Sponsors Initial Comments at 17-18; Southern Initial Comments at 20-21; Utah Commission Initial Comments at 8-9; Undersigned States Reply Comments at 3-4.

[515] Louisiana Commission Initial Comments at 6.

[516] *Id.* at 12 (citing 597 U.S. 697, 729-30, 735).

204. SERTP Sponsors argue that *West Virginia v. EPA* reinforces the need for the Commission to exercise restraint in expanding its jurisdiction without a clear Congressional delegation of authority.[517] According to SERTP Sponsors, *West Virginia v. EPA* makes clear that the nation's energy policy and generation mix is a "major question" for which the Commission must have direct authorization from Congress to assert jurisdiction.[518] SERTP Sponsors contend that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and thereby effect particular substantive transmission outcomes.[519] Rather, SERTP Sponsors argue that Congress instead expressly and unequivocally reserved generation authority to the states.[520]

205. Southern similarly argues that *West Virginia v. EPA* makes clear that the nation's energy policy and generation mix is a "major question" that requires more than a "merely plausible textual basis" for a federal agency to assert jurisdiction.[521] Southern contends that, as applied to the NOPR proposal's "contemplated foray into [integrated resource

[517] SERTP Sponsors Initial Comments at 17 (citing *West Virginia v. EPA*, 597 U.S. at 723); *see also* EEI Initial Comments at 8 (urging the Commission to consider the overlap of the Commission's and state commissions' respective jurisdictions).

[518] SERTP Sponsors Initial Comments at 17-18.

[519] *Id.* at 18.

[520] *Id.*

[521] Southern Initial Comments at 20-21 (citing *West Virginia v. EPA*, 597 U.S. at 723).

planning] and generation/resource matters," the Commission does not rely upon a specific and clear grant of congressional authorization but instead relies upon its "general, gap-filling authorization in FPA Section 206 to regulate a 'practice' affecting a rate or charge for transmission."[522] Southern contends that rather than provide clear congressional authorization, Congress instead reserved authority over integrated resource plans and generation to the states.[523]

206. Utah Commission argues that the Commission has no authority to enact any rule for the purpose of influencing the resource generation mix or expanding development of any type of generation. Utah Commission states that the increased development and integration of renewable generation is a "highly charged political question and a matter of significant political interest about which state legislatures have made very different policy choices." As such, Utah Commission argues that, although courts have given the Commission "some latitude under FPA Section 206," the U.S. Supreme Court will not uphold a final rule premised upon the Commission's "claimed authority to prescribe a single, onerous national regime for transmission planning specifically intended to pressure transmission providers to select costly expansions into remote areas for the purpose of realizing [the Commission's] preferred generation mix, a matter specifically reserved to the states."[524] Utah Commission explains that the Supreme Court's reasoning

[522] *Id.*

[523] *Id.* at 21.

[524] Utah Commission Initial Comments at 8.

in *West Virginia v. EPA* is applicable to the Commission. Utah Commission argues that "imposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of [the Commission's] authority under FPA Section 206."[525]

207. Undersigned States argue that "[n]ational-scale energy grid regulation" is a "major question" because of the "massive economic consequences" involved and the implication of a "unique and complex jurisdictional divide between [s]tate and federal regulatory authority."[526] According to Undersigned States, the Commission "has no statutory authority at all—much less 'clear congressional authorization'—to revamp the energy grid's mix of generation resources writ large."[527]

208. Harvard ELI and Policy Integrity disagree with Undersigned States. They argue that Undersigned States "mischaracterize the NOPR" because the NOPR would not revamp the energy grid's mix of generation resources. Rather, according to Harvard ELI and Policy Integrity, the NOPR would require utilities to amend their existing regional

[525] *Id.* at 8-9 (citing *West Virginia v. EPA*, 597 U.S. at 729-30).

[526] Undersigned States Reply Comments at 3 (citing *West Virginia v. EPA*, 597 U.S. 697; *Ala. Ass'n of Realtors v. HHS*, 594 U.S. 758, 764 (2021)).

[527] *Id.* at 4 (quoting *West Virginia v. EPA*, 597 U.S. at 723).

transmission planning processes in response to changes in the resource mix and demand that are occurring because of factors unrelated to the NOPR.[528]

209. Harvard ELI and Policy Integrity also contend that Undersigned States overlook the major questions doctrine's key requirements. They assert that application of the major questions doctrine does *not* turn on whether a regulation will have significant economic effects or intrudes on areas traditionally regulated by states. Instead, Harvard ELI and Policy Integrity assert that the major questions doctrine is triggered only when an agency's action is both unheralded and transformative.[529]

210. Harvard ELI and Policy Integrity argue that the NOPR is not unheralded. They explain that Order No. 1000 similarly regulated transmission planning and cost allocation in response to concerns about the generation mix, and that the D.C. Circuit upheld Order No. 1000 while rejecting arguments similar to those that Undersigned States make here.[530] Moreover, Harvard ELI and Policy Integrity identify provisions in existing tariffs that are similar to those that the NOPR proposes and point to other antecedents for Commission regulation of regional transmission planning.[531]

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[528] Harvard ELI and Policy Integrity Supplemental Comments at 2.

[529] *Id.* at 2-3.

[530] *Id.* at 4 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 48-49; Order No. 1000, 136 FERC ¶ 61,051 at PP 45, 47).

[531] *Id.* at 4-5; *id.* app. A.

211. Likewise, Harvard ELI and Policy Integrity argue that the NOPR does not represent a transformative expansion in the Commission's authority nor a "fundamental change to the statutory scheme."[532] Instead, they assert that the NOPR merely builds on existing regional transmission planning processes to ensure that Commission-jurisdictional rates remain just and reasonable, as the FPA requires.[533]

### iii. "Equal Sovereignty Doctrine"/Cross-Subsidization

212. Some commenters argue that the NOPR's cost allocation proposal impermissibly requires states to subsidize other states' public policies.[534] Undersigned States argue that the NOPR would exceed the Commission's jurisdiction because it violates the Constitution's equal sovereignty doctrine, which provides constitutional equality among the states.[535] According to Undersigned States, the NOPR "sets up a scheme where one [s]tate can effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation—a core, sovereign [s]tate function," which risks "undue discrimination" among states.[536] Mississippi Commission argues that

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[532] *Id.* at 6-7 (quoting *West Virginia v. EPA*, 597 U.S. at 723 (internal quotations omitted)).

[533] *Id.*

[534] Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 29; Mississippi Commission Reply Comments at 3; Ohio Commission Federal Advocate Initial Comments at 4-5; Ohio Consumers Reply Comments at 14.

[535] Undersigned States Reply Comments at 5-6 (citing *Coyle v. Smith*, 221 U.S. 559, 567 (1911)).

[536] *Id.* at 6 (citing NOPR, 179 FERC ¶ 61,028, Danly, Comm'r, dissenting, at PP 4-5).

unanimous agreement, rather than majority agreement, would be required for any *ex ante* default cost allocation method, as each state has sole jurisdiction within its boundaries.[537]

213. Louisiana Commission asserts that "*group* state oversight" is not equivalent to "state oversight," and that the Commission should not adopt a rule that subjects one state's will to majority override. Louisiana Commission further argues that the Commission should not enact rules that would "impose costs for projects selected under the proposed long-term planning criteria on unwilling states that do not benefit from those projects, even if those states are in the minority." Louisiana Commission contends that the Commission should not attempt to override state jurisdiction simply because a majority of states in a region may support imposing costs on unwilling states that do not benefit from transmission projects favored by the majority.[538] Louisiana Commission argues that states should not be required to cede their jurisdiction by engaging in any "consulting" committee structure required with respect to Long-Term Regional Transmission Planning,[539] because granting each state one vote in a multi-state body cannot replace the meaningful exercise of state jurisdiction within a state's borders.[540]

[537] Mississippi Commission Reply Comments at 2-3.

[538] Louisiana Commission Initial Comments at 27-28; Louisiana Commission Reply Comments at 14-16.

[539] Louisiana Commission Initial Comments at 28-29.

[540] Louisiana Commission Reply Comments at 16.

214. Conversely, ACEG disputes these claims, which ACEG states are "incorrect and misconstrue the NOPR."[541] ACEG highlights the fact that the NOPR does not include resource preferences in its proposed planning criteria, factors, or benefits, nor does the NOPR exclude consideration of non-renewable resources from transmission planning.[542] ACEG further notes that the NOPR proposes to direct transmission planners to plan the system to "meet transmission needs driven by changes in the resource mix and demand," requiring transmission planners to consider the resource mix as a whole, which necessarily requires considering all types of resources.[543] New Jersey Commission agrees, stating that the Commission did not propose in the NOPR "to unduly favor, mandate, or subsidize forms of generation," but rather "to ensure that the bulk electricity system maintains reliability and satisfies evolving consumer demands, whether driven by public policy requirements or voluntary goals, at the lowest reasonable cost."[544] Moreover, New Jersey Commission argues, allocating the cost of Long-Term Regional Transmission Facilities only to those states with relevant public policy goals "would allow the remaining states to free ride, and effectively force the states with public policy

[541] ACEG Reply Comments at 18.

[542] *Id.* at 18-19.

[543] *Id.* at 19.

[544] New Jersey Commission Initial Comments at 3.

goals to subsidize the provision of normal electricity service in other states in order to pursue their own policies."[545]

### i. Other Issues

215. NRECA requests that the Commission clarify that the final rule, consistent with the Commission's obligation under FPA section 217(b)(4), "is intended to facilitate and support 'bottom-up' transmission planning to meet the transmission needs of [load-serving entities] to provide reliable and economical service to consumers."[546]

216. Some commenters argue that the final rule will not withstand judicial scrutiny if it does not permit regional flexibility.[547] For example, US Chamber of Commerce explains that the interstate power grid includes investor-owned utilities, publicly-owned utilities, and electric cooperatives, which can be members of RTOs/ISOs, power pooling arrangements, joint-ownership agreements, or subject to traditional vertically-integrated structures.[548] According to US Chamber of Commerce, imposing a new regional transmission planning regime on all these various entities would ignore the compromises and benefits that led to the status quo.[549] Relatedly, Southern and SERTP Sponsors argue

[545] *Id.* at 20.

[546] NRECA Initial Comments at 17-21.

[547] SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1-2; Southern Initial Comments at 1; Southern Reply Comments at 3; US Chamber of Commerce Initial Comments at 4.

[548] US Chamber of Commerce Initial Comments at 4.

[549] *Id*.

that the legal viability of the final rule will be threatened if the Commission fails to respect the FPA's fundamental jurisdictional roles by not providing states and transmission providers with the opportunity and flexibility to adapt their planning processes.[550]

### j. Miscellaneous Concerns

217. MISO seeks clarification from the Commission that the term "transmission planning region" has the same meaning as in Order No. 1000, where MISO may comprise a single transmission planning region despite including multiple transmission zones or local balancing authorities.[551]

218. California Municipal Utilities state that transmission planning should not be a vehicle to centralize resource choices, but instead should reflect the choices made by state and local authorities.[552] Similarly, Mississippi Commission argues that Long-Term Regional Transmission Planning should be driven by state-specific concerns and needs and that regional priorities should be subordinated to state priorities.[553] Mississippi Commission asks that the Commission not issue a final rule but instead establish proceedings to address specific concerns with certain regional transmission planning

[550] Southern Initial Comments at 1; Southern Reply Comments at 3; SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1-2.

[551] MISO Initial Comments at 24.

[552] California Municipal Utilities Reply Comments at 2.

[553] Mississippi Commission Initial Comments at 3.

processes on a more limited basis.[554] Southern argues that Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions must have the support of affected states, as these facilities stem from resource and load assumptions that are not the result of those states' planning and procurement processes.[555] Southern urges the Commission to maintain the appropriate transmission planning and state-driven supply- and demand-side relationships, which Order No. 1000 preserved.[556] SERTP Sponsors argue that the Commission should avoid mandates that could largely result in transmission expansion or infrastructure decisions that lead to investments borne, largely, by retail electricity consumers that lack the consent and support of the state authorities vested with the responsibility to protect those consumers.[557]

219. Several commenters agree with the Commission that any final rule should apply to transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions.[558] However, several commenters disagree and argue that the final rule, or certain specified requirements in the final rule, should apply only to RTO/ISO transmission

[554] *Id*. at 9.

[555] Southern Initial Comments at 8.

[556] *Id*. at 12.

[557] SERTP Sponsors Initial Comments at 6-7.

[558] *See, e.g.*, AEE Reply Comments at 11; MISO Reply Comments at 3; PIOs Reply Comments at 2-3; SEIA Reply Comments at 5; SREA Initial Comments at 47; TAPS Initial Comments at 70.

planning regions.[559] Nevada Commission argues that the RTOs/ISOs "may be better suited" than other regions for the transmission planning that the NOPR proposes.[560] Utah Division of Public Utilities stresses the need for regional flexibility, noting that transmission providers located outside of RTOs/ISOs already coordinate on transmission planning with many non-Commission-jurisdictional entities.[561]

220. SEIA rebuts the claims of Southern and Louisiana, Utah, Mississippi, and Alabama Commissions that state planning processes already interact well with transmission planning and support customers' transmission needs.[562] SEIA and SREA assert that non-RTO/ISO transmission planning regions do not engage in sufficient or transparent transmission planning.[563] Specifically, SEIA states, the transmission planning processes in non-RTO/ISO regions are rife with issues, including the use of inconsistent and inaccurate data and an exclusionary and insufficiently transparent process.[564] Further, SEIA states that the end result of an integrated resource planning process may be

[559] *See, e.g.*, Mississippi Commission Initial Comments at 16; Utah Division of Public Utilities Reply Comments at 1-2.

[560] Nevada Commission Initial Comments at 2-4.

[561] Utah Division of Public Utilities Reply Comments at 1-2.

[562] SEIA Reply Comments at 5.

[563] *Id.*; SREA Reply Comments at 15-17.

[564] SEIA Reply Comments at 5-6.

based on inconsistent and inaccurate data,[565] the process is "sometimes disjointed,"[566] and the process is a voluntary process in which the planning authority must accept, and not verify, the information provided.[567]

221. SREA rebuts Southern's contention that Southern's transmission planning processes are adequate, noting that Southern itself has presented testimony to the Georgia Commission conceding that it is unable to perform more robust transmission planning due to limitations in its software and models.[568] SREA argues that throughout the Southeast, transmission planning is not a priority and that integrated resource planning is not a substitute for robust transmission planning.[569] SREA explains that the NOPR borrows many of the qualities of integrated resource planning and applies them to transmission planning, including scenario-based evaluation and use of 20-year planning horizons, and that many states have integrated resource planning rules and guidelines that recognize the value of long-term planning.[570]

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[565] *Id*. at 5 (citing Western PIOs Initial Comments at 10).

[566] *Id.* (citing PacifiCorp and NV Energy Initial Comments at 10).

[567] *Id.* (citing PacifiCorp and NV Energy Initial Comments at 13; Western PIOs Initial Comments at 11).

[568] SREA Reply Comments at 7 (citing SREA Initial Comments, attach. B (Testimony of Georgia Power Witness Robinson) at 282-283).

[569] *Id.* at 5.

[570] *Id*.

222. EPSA states that the Commission should focus not on socializing transmission costs but on reducing transaction costs, accelerating lagging processes, and adopting market-based solutions like open seasons.[571]

223. GridLab states that there is evidence to suggest that changes in resource mix, demand, and weather will lead to significant changes in the value of regional transmission facilities in the 2030s, though GridLab asserts that these changes may increase or decrease the value of regional transmission facilities. Accordingly, GridLab recommends that the Commission and stakeholders resist evaluating the success of this rulemaking based on arbitrary metrics related to each transmission provider's expansion of regional transmission facilities.[572]

### 3. Commission Determination

#### a. Participation in Long-Term Regional Transmission Planning

224. We adopt the NOPR proposal to require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those

[571] EPSA Initial Comments at 7-8.

[572] GridLab Initial Comments at 9-10.

transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.[573] We also adopt the NOPR proposal to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[574] In developing their compliance filings, transmission providers and stakeholders should review the requirements set forth in Order No. 890 and Order No. 1000, and the Commission's orders on compliance filings submitted by transmission providers, for guidance as to what each of these transmission planning principles requires. For example, as a starting point, a transmission provider should review the orders addressing its own Order Nos. 890 and 1000 compliance filings and the compliance filings for transmission providers in its transmission planning region.

225. We also adopt specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning. Specifically, and as discussed

[573] We note that, while we have modified this definition of Long-Term Regional Transmission Planning from the NOPR proposal, the modified definition does not substantively change the steps involved in Long-Term Regional Transmission Planning from those proposed in the NOPR. Rather, the revised definition merely clarifies the steps that transmission providers must take in conducting Long-Term Regional Transmission Planning.

[574] Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 151. We do not address these principles in detail here.

further below, we require transmission providers in each transmission planning region[575] to: (1) identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios[576] that satisfy the requirements set forth in this final rule; (2) use and measure, at a minimum, a set of seven required benefits[577] to evaluate Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of each transmission facility; and (3) evaluate Long-Term Regional Transmission Facilities to determine whether they are more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs and use selection criteria (in collaboration with states and other stakeholders) that provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities.

[575] In response to MISO's request, MISO Initial Comments at 24, we clarify that this final rule does not alter the meaning of "transmission planning region" as used in Order No. 1000. A transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. Order No. 1000-A, 139 FERC ¶ 61,132 at P 272; Order No. 1000, 136 FERC ¶ 61,051 at P 160.

[576] The requirements related to Long-Term Scenarios are discussed below.

[577] As discussed further below in the Evaluation of the Benefits of Regional Transmission Facilities section, these seven benefits are: (1) Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement; (2) Benefit 2(a), Reduced Loss of Load Probability, or Benefit 2(b), Reduced Planning Reserve Margin; (3) Benefit 3, Production Cost Savings; (4) Benefit 4, Reduced Transmission Energy Losses; (5) Benefit 5, Reduced Congestion Due to Transmission Outages; (6) Mitigation of Extreme Weather Events and Unexpected System Conditions; and (7) Capacity Cost Benefits from Reduced Peak Energy Losses.

226. These requirements together establish a long-term, forward-looking, and more comprehensive approach to regional transmission planning, which will ensure that transmission providers identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs. Long-Term Regional Transmission Planning, as set forth in this final rule, requires regional transmission planning based on a multitude of drivers of Long-Term Transmission Needs and provides the opportunity for transmission providers to meet those needs by selecting more efficient or cost-effective Long-Term Regional Transmission Facilities.

227. In considering the comments received on this proposal, we strike a careful balance. On the one hand, we believe that there is an inherent risk in transmission providers waiting for the near-term certainty that some commenters appear to believe is necessary[578] before planning to address transmission needs. As explained in the Overall Need for Reform section above, doing so may result in transmission providers relying on relatively inefficient and less cost-effective piecemeal transmission solutions to address these needs shortly before they manifest, to the detriment of customers. On the other hand, we acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs and that this uncertainty means that forward-looking regional transmission planning entails certain risks, including the risk that transmission needs may change over time. In this final rule, we balance these risks, requiring planning to meet

[578] *See, e.g.*, NRG Initial Comments at 8 (arguing that there are unlikely to be any "no regrets" options).

Long-Term Transmission Needs, while imposing requirements on how Long-Term Regional Transmission Planning is conducted, as discussed further herein, to mitigate uncertainty. To adequately prepare for the future, transmission providers need to make decisions in the present that are grounded in a thorough, informed analysis of the factors that drive Long-Term Transmission Needs.

228. As discussed in the Overall Need for Reform section, these factors are together driving rapid changes in the Long-Term Transmission Needs that transmission providers must plan to meet to continue to provide an affordable, reliable supply of electricity to customers, but neither transmission infrastructure nor regional transmission planning processes are keeping pace. Consequently, the Commission's existing regional transmission planning requirements are no longer just and reasonable, as they increasingly result in transmission investment decisions occurring outside of regional transmission planning processes and instead through generator interconnection processes and local transmission planning processes that typically plan to meet discrete, nearer-term transmission needs. In addition, the record demonstrates that transmission providers have made substantial investments in in-kind replacement transmission facilities, which generally are not identified through more long-term, forward-looking, or comprehensive transmission planning. This final rule aims to ensure that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, helping to ensure just and reasonable rates.

229. We disagree with arguments that the Commission should not require Long-Term Regional Transmission Planning because, certain commenters claim, doing so will introduce excessive uncertainty into regional transmission planning, transmission providers will make forecasting errors, or the final rule will result in regional transmission planning that is speculative.[579] To the contrary, we believe that the reforms adopted in this final rule account for and seek to reduce the inherent uncertainty in forward-looking regional transmission planning, while ensuring that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, thus helping to ensure just and reasonable rates.[580] In fact, by requiring transmission providers to use Long-Term Scenarios in Long-Term Regional Transmission Planning, this final rule provides transmission providers with a critical tool for managing uncertainty, facilitating regional transmission planning that accounts for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate Long-Term Regional Transmission

[579] Louisiana Commission Initial Comments at 4-5; NRG Initial Comments at 3-4; Ohio Consumers Initial Comments at 5.

[580] *See* Policy Integrity Initial Comments at 6 (arguing that future uncertainty requires scenario planning).

Facilities in certain circumstances, which will provide transmission providers with yet another such tool.

230. Moreover, notwithstanding allegations to the contrary, we believe that Long-Term Regional Transmission Planning is a logical and reasonable extension of current regional transmission planning processes, which also manage uncertainty and plan for future regional transmission needs. The key difference, which we address through this final rule, is that these existing regional transmission planning processes are conducted in a manner that is not sufficiently long-term, forward-looking, or comprehensive such that transmission providers are not identifying Long-Term Transmission Needs. As a result, transmission providers are failing to identify or evaluate regional transmission facilities that would more efficiently or cost-effectively address those Long-Term Transmission Needs, and consequently, are missing the opportunity to select such regional transmission facilities. Our reforms in this final rule remedy these deficiencies.

231. Further, we believe that Long-Term Regional Transmission Planning as set forth in this final rule provides adequate safeguards against excessive transmission development in response to speculative transmission needs. For example, this final rule requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios based upon best available data, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and requires transmission providers to update their assumptions

periodically, as discussed further below.[581] In developing these Long-Term Scenarios, transmission providers are required to treat more certain drivers of Long-Term Transmission Needs differently than less certain drivers, and must provide opportunities for stakeholder engagement. Further, the final rule grants substantial flexibility to transmission providers to develop an evaluation process and selection criteria that will provide them with the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities. Consistent with the existing Order No. 1000 regional transmission planning processes, the final rule does not require transmission providers to select any regional transmission facilities as part of Long-Term Regional Transmission Planning. Finally, we require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities in certain circumstances, as discussed further below in the Reevaluation section.

232. The regional transmission planning and cost allocation requirements in this final rule, like those of Order Nos. 890 and 1000, are focused on the transmission planning *process*, and do not require any substantive outcomes from this process.[582] We disagree with certain commenters' assertions that this final rule favors, promotes, or subsidizes particular types of generation resources over others, or otherwise engages in generation

[581] *See* New Jersey Commission Initial Comments at 10-11.

[582] *See, e.g.*, Order No. 1000, 136 FERC ¶ 61,051 at P 12.

planning.[583] Instead, this final rule requires transmission providers to participate in Long-Term Regional Transmission Planning through their regional transmission planning process that identifies Long-Term Transmission Needs, evaluates the benefits of Long-Term Regional Transmission Facilities to meet those needs, and provides the opportunity for transmission providers to select Long-Term Regional Transmission Facilities that are more efficient or cost-effective transmission solutions to those needs. We reiterate that, as discussed below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, any selected Long-Term Regional Transmission Facilities must satisfy transmission provider-developed selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities, which ensures that the costs of such transmission facilities are outweighed by the benefits they deliver to customers.

233. We disagree with commenters that argue that the factors giving rise to Long-Term Transmission Needs, such as state laws dictating specific generation resource mixes, are irreconcilable with effective transmission planning.[584] These changes are occurring independent of any action that we take in this final rule, and they are being driven by a wide variety of factors. This final rule provides transmission providers with the tools that they need to respond to these factors, requiring that they conduct Long-Term Regional

[583] Alabama Commission Initial Comments at 7-8; Louisiana Commission Initial Comments at 12, 19-21; Potomac Economics Initial Comments at 3-4; Utah Division of Public Utilities Initial Comments at 2; Vistra Initial Comments at 11.

[584] *See* ELCON Initial Comments at 9 ("ELCON has always believed that planning for disparate state energy priorities is at odds with market-driven, efficient, and cost-effective transmission planning.").

Transmission Planning to identify, evaluate, and select Long-Term Regional Transmission Facilities that are more efficient or cost-effective regional transmission solutions to the Long-Term Transmission Needs that these factors drive.

234. We disagree with Louisiana Commission and former Kansas Commission Chairman Keen's claims that Long-Term Regional Transmission Planning will threaten the reliability of the transmission system. We acknowledge that reliability needs are evolving; for example, the increasing frequency and severity of high-impact extreme weather events threatens grid reliability. We believe that Long-Term Regional Transmission Planning—in addition to existing Order No. 1000 regional transmission planning and cost allocation requirements—is needed to support the reliable operation of transmission systems, given these changes. As the Commission and the North American Electric Reliability Corporation have noted, the transmission system may not be adequately prepared for extreme weather events and the increasing frequency of these events must be planned for to ensure system reliability.[585] We thus view our action in this final rule as complementary to other steps that the Commission has taken in recent years to bolster system reliability.[586]

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[585] FERC, North American Electric Reliability Corporation, *Winter Storm Elliot Report: Inquiry into Bulk-Power System Operations During December 2022* (Nov. 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022; FERC, North American Electric Reliability Corporation, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[586] *See, e.g.*, *Transmission Sys. Planning Performance Requirements for Extreme Weather*, Order No. 896, 88 FR 41262 (June 23, 2023), 183 FERC ¶ 61,191 (2023); *One-*

235. Further, we disagree with the contention of Louisiana Commission and Vistra that Long-Term Regional Transmission Planning will distort the efficient functioning of Commission-jurisdictional wholesale markets by subsidizing uneconomic generation or by distorting price signals. As discussed further below, we require transmission providers, as part of Long-Term Regional Transmission Planning, to assess the costs and measure the benefits of regional transmission facilities that address Long-Term Transmission Needs and to develop evaluation processes and selection criteria that provide the opportunity to select those transmission facilities as more efficient or cost-effective regional transmission solutions to those Needs. While the addition of any new transmission facility necessarily affects Commission-jurisdictional wholesale markets, the requirements set forth in this final rule ensure that transmission providers will have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities that provide value to transmission customers and support the efficient functioning of wholesale markets by addressing Long-Term Transmission Needs.

236. We also disagree with Vistra's contention that Long-Term Regional Transmission Planning somehow will assign all, or a disproportionately high share, of interconnection-related network upgrade costs to load or undermine the incentives for generation developers to site new generation resources in ways that minimize transmission system

*Time Info. Reports on Extreme Weather Vulnerability Assessments*, Order No. 897, 88 FR 41447 (June 27,2023), 183 FERC ¶ 61,192 (2023).

upgrade costs. Rather, because transmission providers will now engage in Long-Term Regional Transmission Planning to identify, evaluate, and select more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs, Long-Term Regional Transmission Facilities will be planned in a more efficient and cost-effective manner than if transmission facilities meeting a narrower set of transmission needs were left to be identified through the generator interconnection process. Indeed, numerous commenters explain that the piecemeal expansion of the transmission system is highly inefficient and results in higher costs for transmission customers,[587] in part because the costs of interconnection-related network upgrades ultimately are passed on to consumers.

237. We strike another careful balance in this final rule. On the one hand, we recognize transmission providers' need for sufficient flexibility to implement Long-Term Regional Transmission Planning in their transmission planning regions to reflect regional differences, such as different market structures.[588] On the other hand, we must ensure that transmission providers' regional transmission planning processes result in just and reasonable rates, which, as discussed above in the Overall Need for Reform section, necessitates that they plan on a sufficiently long-term, forward-looking, and comprehensive basis such that transmission providers are identifying, evaluating, and

[587] *See, e.g.*, NYISO Initial Comments at 30; PIOs Initial Comments at 9-10.

[588] The Commission also recognized the need for sufficient flexibility in regional transmission planning to reflect regional differences in Order No. 1000. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 61.

selecting more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs. We believe that the balance struck in the final rule will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential and, thus, we reject requests for flexibility that exceeds that provided in this final rule.

238. In particular, we reject requests that, instead of requiring transmission providers to implement Long-Term Regional Transmission Planning in accordance with the requirements adopted in this final rule, we set forth principles and objectives articulating our concerns with existing regional transmission planning processes and give transmission providers the flexibility to propose revisions to their processes to address those concerns.[589] Having found existing regional transmission planning and cost allocation requirements to be unjust and unreasonable, we have an obligation under FPA section 206 to adopt reforms that remedy the deficiencies identified in this final rule. We also believe that such an approach would fail to adequately address the deficiencies described above in the Overall Need for Reform section, namely that transmission providers are not currently required to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities

[589] ISO-NE Initial Comments at 20; ISO RTO Council Initial Comments at 4-5, 8-9; MISO Initial Comments at 22-23.

planned to meet those Long-Term Transmission Needs. We further believe that establishing requirements rather than principles will ensure a sufficiently robust process for Long-Term Regional Transmission Planning while providing sufficient clarity about that process to avert conflict among stakeholders, as noted by AEP.[590]

239. We also disagree with commenters that argue that this final rule should apply to only RTO/ISO transmission planning regions. The Commission's existing regional transmission planning requirements, which, as described above in the Overall Need for Reform section, we find to be deficient, apply in RTO/ISO and non-RTO/ISO transmission planning regions alike; without the Long-Term Regional Transmission Planning Requirements adopted herein, transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions will continue to be at risk of undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, while we acknowledge differences between RTO/ISO and non-RTO/ISO transmission planning regions, we find that transmission providers in all transmission planning regions must implement Long-Term Regional Transmission Planning as required in this final rule to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. Additionally, we note that many of the requirements established in this final rule provide for regional flexibility, including, but not limited to, the requirements to develop Long-Term Scenarios,

[590] AEP Reply Comments at 2-4.

determine which factors in each required category of factors do not affect Long-Term Transmission Needs and need not be considered, develop methods to measure the benefits of Long-Term Regional Transmission Facilities, design an evaluation process and selection criteria, and establish a Long-Term Regional Transmission Cost Allocation Method.

240. We acknowledge that certain transmission planning regions already conduct some regional transmission planning on a relatively forward-looking, proactive basis. We do not intend to undermine progress made in these transmission planning regions, and our goal is to set a floor, not a ceiling. We decline to prejudge whether any existing regional transmission planning process meets the requirements set forth in this final rule and accordingly reject requests that we do so.[591] We note that, if a transmission provider believes that it participates in a regional transmission planning process that fulfills the requirements adopted in this final rule, it may describe in its compliance filing how its process meets these requirements.

241. We expect Long-Term Regional Transmission Planning to enhance the existing regional transmission planning and cost allocation processes required by Order No. 1000. Except as set forth in this final rule, we do not require that any transmission provider replace or otherwise make changes to its existing Order No. 1000-compliant regional transmission planning processes that plan for reliability or economic transmission needs, or the associated Order No. 1000-compliant regional cost allocation method(s).

[591] *See, e.g.*, Ameren Initial Comments at 8.

Transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.

242. We also do not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process. Instead, we clarify that we will deem transmission providers to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final rule. As discussed below, we require transmission providers to incorporate a variety of factors into the development of Long-Term Scenarios, which include, among others, certain federal, state, and local laws and regulations. Therefore, we find that transmission providers that implement Long-Term Regional Transmission Planning and satisfy the requirements set forth in this final rule will comply with the requirement in Order No. 1000 to participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.

243. We understand—and acknowledge comments submitted in this proceeding explaining—that transmission providers in some transmission planning regions have developed processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes that they wish to

retain.[592] In their filings made to comply with this final rule, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements. Transmission providers must nevertheless comply with the Long-Term Regional Transmission Planning requirements set forth in this final rule, such that continued use of existing regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements will not supplant transmission providers' obligation to comply with this final rule. In their filing to comply with this final rule, transmission providers that wish to continue to use some or all of their existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final rule.

244. Similarly, we allow transmission providers to propose a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs, as well as Long-Term Transmission Needs, as outlined in this final rule, through a combined process. Transmission providers proposing to address all of these transmission needs in a single regional transmission planning process must demonstrate that the unified regional transmission planning process continues to comply with Order No. 1000, as well as with the Long-Term Regional Transmission Planning

[592] CAISO Reply Comments at 17-18; New York Transco Initial Comments at 5.

requirements set forth in this final rule, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order No. 1000 and this final rule. However, in the case that the requirements of Order No. 1000 and this final rule conflict, the requirements of this final rule prevail, and transmission providers must demonstrate that their proposed regional transmission planning process is consistent with or superior to the applicable requirements in this final rule.

245. We reject requests to require transmission providers to simultaneously plan for all such transmission needs through a single regional transmission planning process, however.[593] We recognize that such a combined process has potential benefits and do not prohibit such an approach, but at this time we believe that the benefits of requiring such a combined process on a generic basis may be outweighed by the difficulty of transitioning to such a process from existing regional transmission planning processes. Therefore, we do not require in this final rule that transmission providers plan for all reliability and economic transmission needs and Long-Term Transmission Needs through a single regional transmission planning process. Further, we believe that Long-Term Regional Transmission Planning, as set forth in this final rule, meets many of the same objectives as would such a combined regional transmission planning process because, by identifying Long-Term Transmission Needs and considering a broad set of benefits when evaluating Long-Term Regional Transmission Facilities, the existing regional transmission planning processes for economic and reliability needs may ultimately come to address only

[593] *See, e.g.*, ACEG Initial Comments at 30-31.

residual needs not already addressed through Long-Term Regional Transmission Planning.

246. With respect to the request by PIOs to mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process,[594] we decline to adopt this proposal. The record is inadequate to assess the impact that such a requirement would have on existing Order No. 1000 regional transmission planning processes, and whether this proposal would work across the differing transmission planning processes in each transmission planning region. With respect to the proposals by Clean Energy Buyers, Cypress Creek, and Policy Integrity,[595] these proposals were not among the proposals included in the NOPR and are beyond the scope of this proceeding, and therefore we decline to adopt them.

247. We also reject requests to incorporate local transmission planning into Long-Term Regional Transmission Planning specifically or regional transmission planning more generally,[596] as well as requests to require transmission providers to evaluate and approve local transmission facilities in regional transmission planning.[597] This final rule sets forth

[594] PIOs Initial Comments at 44-46.

[595] Clean Energy Buyers Initial Comments at 9-10; Cypress Creek Reply Comments at 10-12; Policy Integrity Supplemental Comments at 3.

[596] AEE Initial Comments at 3, 38.

[597] OMS Initial Comments at 16-17.

requirements that will enhance the transparency of local transmission planning and examine opportunities for right-sizing in-kind replacements of existing transmission facilities, including local transmission facilities, but the Commission in the NOPR did not propose other changes to local transmission planning processes and therefore these requests are beyond the scope of this final rule.

248. As discussed in detail below, we require transmission providers to satisfy specific requirements in implementing Long-Term Regional Transmission Planning, including requirements to: (1) use a transmission planning horizon of no less than 20 years into the future in developing Long-Term Scenarios; (2) reassess and revise those scenarios at least once every five years; (3) incorporate into the Long-Term Scenarios a set of Commission-identified categories of factors that give rise to Long-Term Transmission Needs; (4) develop a plausible and diverse set of at least three Long-Term Scenarios; (5) perform sensitivity analyses of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area; and (6) use "best available data" in developing Long-Term Scenarios.

249. Before turning to these topics, however, we address two preliminary matters: the definition of Long-Term Regional Transmission Facility; and our jurisdiction to adopt these reforms.

### b. Definition of Long-Term Regional Transmission Facility

250. We modify the NOPR proposal and define Long-Term Regional Transmission Facility for purposes of this final rule as a regional transmission facility, as defined in

Order No. 1000, that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.[598] In so doing, we clarify that some Long-Term Regional Transmission Facilities may be selected in a regional transmission plan for purposes of cost allocation, while others may be considered for selection but not be selected.

251. This modification also clarifies that Long-Term Regional Transmission Facilities are a subset of regional transmission facilities as defined in Order No. 1000. Further, consistent with Order No. 1000,[599] a selected Long-Term Regional Transmission Facility is a regional transmission facility that has been selected pursuant to a Commission-approved Long-Term Regional Transmission Planning process in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective solution to Long-Term Transmission Needs.

252. We disagree with PJM that Order No. 1000's requirements related to regional transmission planning processes addressing transmission needs driven by reliability concerns or economic considerations will be unclear given the definition of Long-Term Regional Transmission Facility, and we find unpersuasive PJM's contention that Long-Term Regional Transmission Planning will inadvertently cause the re-litigation of aspects

[598] In the NOPR, the Commission proposed to define a Long-Term Regional Transmission Facility as a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. NOPR, 179 FERC ¶ 61,028 at P 252 n.398.

[599] Order No. 1000, 136 FERC ¶ 61,051 at P 63.

of those existing processes. If a regional transmission facility is selected in an existing Order No. 1000 regional transmission planning process, the rules of, as well as the regional cost allocation method for, that existing process apply to the selected regional transmission facility. If a Long-Term Regional Transmission Facility is selected in Long-Term Regional Transmission Planning, then the rules of, and the Long-Term Regional Cost Allocation Method for, Long-Term Regional Transmission Planning apply to that Long-Term Regional Transmission Facility.

### c. Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning

253. We reaffirm our conclusion in the NOPR that we are acting within the Commission's legal authority under FPA section 206 by requiring transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning. The FPA grants the Commission authority over the transmission of electric energy in interstate commerce, which includes transmission on the interconnected national grids.[600] FPA section 205 requires that the rates charged by any public utility in connection with such transmission—as well as the rules and regulations affecting such rates—be just and reasonable, and further requires that public utilities file with the Commission the practices affecting such rates.[601] Under FPA section 206, when the Commission determines that any rate or any practice affecting such

[600] *New York v. FERC*, 535 U.S.at 16-17 (citing 16 U.S.C. 824(b)).

[601] 16 U.S.C. 824d.

rate is unjust, unreasonable, or unduly discriminatory or preferential—as we find above with respect to transmission planning practices—the Commission must determine the just and reasonable rate or practice to be followed.[602] Transmission planning and cost allocation processes are practices affecting the rates charged by public utilities in connection with the Commission-jurisdictional transmission of electric energy in interstate commerce.[603] No commenter has claimed otherwise.

254. Despite this, a number of commenters claim that the specific transmission planning requirements we adopt in this final rule infringe on the authority reserved to the states by FPA section 201 or are otherwise barred by certain prudential or constitutional principles. As a threshold matter, we believe that commenters' concerns with respect to our jurisdiction or authority to adopt this final rule mainly arise from factual misunderstandings or mischaracterizations about what Long-Term Regional Transmission Planning will and will not require transmission providers to do. As explained above, this final rule requires transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning and to conduct Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final rule. Transmission providers are required to identify Long-Term Transmission Needs, identify

[602] 16 U.S.C. 824e.

[603] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-59; *accord Emera Me. v. FERC*, 854 F.3d at 673-74.

Long-Term Regional Transmission Facilities that meet such needs, measure the benefits of these Long-Term Regional Transmission Facilities, and evaluate these Long-Term Regional Transmission Facilities for potential selection. As such, this final rule does not regulate, aim at, or otherwise attempt to influence integrated resource planning, the generation mix, decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states under FPA section 201.

255. As discussed in the Introduction and Background section above, the requirements of this final rule build upon more than a quarter century of significant actions taken by the Commission on transmission planning and cost allocation, beginning with the Commission's initial open access reforms in Order No. 888. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT based on more than 10 years of experience since the issuance of Order No. 888. Most recently, in 2011, the Commission issued Order No. 1000, which required transmission providers to develop a regional transmission plan after evaluating whether regional transmission facilities may be more efficient or cost-effective than transmission facilities identified in local transmission planning processes and to consider transmission needs driven by Public Policy Requirements. These practices serve as the foundation for regional transmission planning, and this final rule leaves them in place.

256. As described above, however, we have identified specific gaps in the Order No. 1000 framework—namely, that regional transmission planning practices do not perform a sufficiently long-term assessment of transmission needs, adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs, or

consider the broader set of benefits of regional transmission facilities. In this final rule, we direct reforms to close these gaps without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal in the face of similar objections to those raised here.[604]

257. Critically, as in Order No. 1000, our focus continues to be on ensuring that Commission-jurisdictional regional transmission planning processes are just and reasonable and that, as a result of improvements to the regional transmission planning and cost allocation processes, Commission-jurisdictional rates remain just and reasonable.[605] And, as in Order No. 1000, while the improvements to the regional transmission planning and cost allocation processes will ensure that potentially more efficient or cost-effective regional transmission facilities are evaluated for potential selection and have a cost allocation method available if they are selected, this rule does not mandate development of any particular transmission facility.

258. Consistent with the regional transmission planning and cost allocation reforms adopted in Order No. 1000, and in response to commenters arguing otherwise,[606] we

[604] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-64 (rejecting arguments that the requirement to engage in regional transmission planning, as prescribed in Order No. 1000, exceeded the Commission's jurisdiction under FPA section 206, interfered with traditional state authority reserved under FPA section 201, or improperly interpreted and applied FPA section 202(a)).

[605] *See id*. at 63-64 (affirming that the Commission was acting within its jurisdiction because its planning mandate "relates wholly to electricity transmission, as opposed to electricity sales" and "is directed at ensuring the proper functioning of the interconnected grid spanning state lines").

[606] Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates

affirm that this final rule does not authorize or require any entity to adopt a particular siting plan for Long-Term Regional Transmission Facilities that transmission providers select; or to forego state-jurisdictional siting proceedings where they are necessary; or to begin construction on such Long-Term Regional Transmission Facilities. Even where transmission providers select a Long-Term Regional Transmission Facility, the relevant transmission developer typically must secure a variety of other permits and authorizations before beginning to construct the facility, including those that are subject to state jurisdiction. Nothing in this final rule changes otherwise applicable siting laws or requirements.

259. Similarly, this final rule does not change existing mechanisms for cost-recovery through retail rates; authorize or require states or state commissions to change the laws or regulations that govern the conduct of integrated resource planning or request for proposal processes; authorize or require transmission providers or transmission developers to bypass any applicable state-regulated integrated resource planning or request for proposal processes; or authorize or require states or public utilities to adopt a different mix of generation resources than would otherwise be the case. Comments suggesting otherwise do not accurately represent the Commission's proposed requirements in the NOPR or the requirements adopted in this final rule,[607] which seeks

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Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2-3; Southern Initial Comments at 3-4, 7, 15-17; Southern Reply Comments at 6-7.

[607] Alabama Commission Initial Comments at 3-4, 7-9; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8-10, 27-

to ensure that transmission providers plan for Long-Term Transmission Needs, however those needs arise.[608]

260. We disagree with Southern and SERTP Sponsors' characterization of Long-Term Regional Transmission Planning as a Commission-regulated integrated resource planning/request for proposal process.[609] Similarly, comments that suggest that this final rule intends to "revamp the energy grid's mix of generation resources writ large"[610] are incorrect. We understand these comments to argue that the Commission seeks reforms to regional transmission planning and cost allocation processes so that it can direct or influence investments toward particular resources, as would an entity engaged in integrated resource planning. In this final rule, the Commission neither aims to influence the resource mix, nor, as a practical matter, could the final rule achieve such an outcome.

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28; Louisiana Commission Reply Comments at 14-15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2); Nevada Commission Initial Comments at 2-3; SERTP Sponsors Initial Comments at 5, 16, 17 n.20, 19-20; SERTP Sponsors Reply Comments at 12-13; Southern Initial Comments at 3-4, 7-8, 12-13, 15-17, 23-24; Southern Reply Comments at 3, 6-7; Undersigned States Reply Comments at 2, 4-5, 8; Utah Commission Initial Comments at 7-9.

[608] New Jersey Commission Reply Comments at 1-2.

[609] SERTP Sponsors Initial Comments at 16-17; Southern Initial Comments at 3-4, 7, 15-17.

[610] Undersigned States Reply Comments at 4; *see also* Louisiana Commission Initial Comments at 6, 12-13 (arguing that the FPA does not allow the Commission to "enact[] sweeping energy policy changes that would have far-reaching, nation-wide effects" or to favor one form of generation over another).

261. Instead, the final rule merely requires transmission providers to account for observable changes affecting the transmission system. The final rule neither directs those changes, nor does it require any entity, including a state, to approve changes to any subject within its jurisdiction. As with Order Nos. 890 and 1000, which built on the Commission's open access reforms in Order No. 888, this final rule *responds* to changes in the electric industry that have arisen in the years since the Commission's last regulatory action related to transmission planning. As discussed above in the Overall Need for Reform section, this final rule responds to evolving reliability concerns, including the increasing frequency of high-impact extreme weather events; changes in electricity demand, including significant load growth that is projected to increase in coming years; changes in supply, including federal, federally-recognized Tribal, state, and local laws and policies that affect the future resource mix; changes in the economics of generation, transmission, and storage technologies; corporate, governmental, and utility commitments to rely on certain generation resources; and other factors as discussed in this final rule.

262. We emphasize that these changes, which are affecting and will continue to drive transmission needs, are not within the Commission's control and, in many cases, are beyond the Commission's jurisdiction. We do not aim to influence these drivers of transmission needs through the requirements in this final rule.[611] However, the

[611] *See EPSA*, 577 U.S. 260 at 282 (citing *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 385 (2015)).

Commission has an obligation under the FPA to ensure that Commission-jurisdictional transmission rates remain just and reasonable, and we affirm—consistent with the Commission's actions in Order Nos. 890 and 1000—that the Commission has the requisite authority to account for the effects of these changes driving transmission needs in Commission-jurisdictional transmission planning processes.[612]

263. We also emphasize, and no commenter contests, that this final rule directly regulates transmission planning and cost allocation processes, which are practices that affect the rates for the transmission of electric energy in interstate commerce. Importantly, it directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201. Moreover, in doing so, this final rule is not aiming to *indirectly* regulate any matter reserved to the states by FPA section 201. Instead, our aim here is to improve on the Commission's existing transmission planning and cost allocation processes *for the express purpose* of addressing identified deficiencies with those processes.

264. As the U.S. Supreme Court has recognized, it is true that almost any action that the Commission takes with respect to regulating the practices affecting the rates for the transmission of or the wholesale sale of electric energy in interstate commerce will have "*some* effect, in either the short or long term" on matters reserved to the states'

[612] *Cf. EPSA*, 577 U.S. at 281-82 ("When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, 824(b) imposes no bar.").

jurisdiction.[613] But those effects, inevitable as they may be, are "of no legal consequence" to determining whether this final rule infringes on the states' authority under FPA section 201.[614] Instead, such effects are a "fact of economic life" for the electric industry, given Congress's decision in the FPA to divide jurisdiction over the industry, including both generation and transmission, into spheres of Commission and state jurisdiction that are not "hermetically sealed" from one another.[615] Accordingly, Commission regulation of Commission-jurisdictional practices affecting transmission may "have natural consequences" for generation.[616] But, even where that happens, that does not defeat federal jurisdiction.

265. Rather, as in *EPSA*, what matters is that this final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA. As in Order Nos. 890[617] and 1000,[618] this final rule aims to improve Commission-regulated transmission planning *processes*, in this instance by ensuring that they are sufficiently long-term, forward-looking, and comprehensive such that they are capable of identifying

[613] *Id*. at 281 (emphasis added).

[614] *Id*.

[615] *Id*.

[616] *Id*.

[617] Order No. 890, 118 FERC ¶ 61,119 at P 3.

[618] Order No. 1000, 136 FERC ¶ 61,051 at P 12.

and meeting Long-Term Transmission Needs.[619] Thus, this final rule ensures just and reasonable Commission-jurisdictional rates and practices by ensuring that transmission providers have adequate processes to identify Long-Term Transmission Needs and to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address those needs.

266. Moreover, as in *EPSA*, what also matters is that "every aspect of the [final rule] happens exclusively" as part of a process that is subject to the Commission's jurisdiction and governs exclusively how those processes work.[620] In aiming to improve transmission planning processes, this final rule does not require that transmission providers achieve any particular substantive *outcome* of those processes, including either the selection or construction of any specific transmission facilities. The final rule patently does not aim to alter states' or the nation's generation mix or otherwise regulate matters that are within state jurisdiction. Indeed, to the contrary, our rationale in this final rule is "all about, and only about, improving" the relevant matters under the Commission's jurisdiction.[621] Nor is it clear how, under commenters' theory, the final rule could be argued to regulate matters under states' jurisdiction, given that the final rule does not require investment in any particular transmission facilities, and could not, even indirectly, ensure investments in any particular set of generating facilities that may rely on such transmission facilities.

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[619] *EPSA*, 577 U.S. at 281-83.

[620] *Id*. at 282.

[621] *Id.* (citing *Oneok, Inc. v. Learjet, Inc.*, 575 U.S.at 385).

267. Despite some commenters' claims,[622] nothing in this final rule requires states to subsidize other states' public policies and, indeed, this final rule requires, consistent with long-established Commission and court precedent, that transmission customers within a transmission planning region need only pay costs that are "roughly commensurate" with the benefits that transmission providers estimate they will receive from a regional transmission facility.[623] Thus, the final rule ensures that transmission customers nationwide are not required to pay for Long-Term Regional Transmission Facilities from which they do not benefit.

268. The reforms in the final rule require greater transparency regarding the benefits that would result from the development of Long-Term Regional Transmission Facilities, but these reforms also continue to allow flexibility, as under Order No. 1000, for the transmission providers in each transmission planning region to determine the appropriate method for allocating to transmission customers the costs of any selected Long-Term Regional Transmission Facility. Rather than force transmission providers to adopt a particular cost allocation method that would necessarily result in customers in one state subsidizing the costs of customers in another state, as these commenters allege, the final

[622] Alabama Commission Initial Comments at 8-9; Louisiana Commission Initial Comments at 6, 9-10; Mississippi Commission Reply Comments at 2-3; Ohio Commission Federal Advocate Initial Comments at 4-6; Ohio Consumers Reply Comments at 14.

[623] *See Ill. Com. Comm'n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (*ICC v. FERC III*); *ICC v. FERC I*, 576 F.3d at 477; *Sw. Power Pool, Inc.*, 182 FERC ¶ 61,141, at P 12 (2023).

rule affords significant new opportunities for Relevant State Entities to inform the evaluation process, selection criteria, and cost allocation method adopted by the transmission providers in a transmission planning region. We believe that the requirements for greater transparency regarding the benefits of proposed transmission facilities, the increased opportunities for state engagement in evaluation, selection, and cost allocation, the flexibility for transmission providers in each transmission planning region to determine their own cost allocation methods, and the requirement that any cost allocation method must ensure costs are allocated in a manner that is at least roughly commensurate with estimated benefits provide robust assurance that the cost allocation methods ultimately proposed under the final rule will not result in improper cost subsidization. Ultimately, the Commission must review and accept each cost allocation method proposed under the final rule to ensure that it is just and reasonable and consistent with the final rule's requirements.

269. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, this final rule requires transmission providers to use and measure a set of seven required benefits to evaluate Long-Term Regional Transmission Facilities. The measurement of these benefits represents the value that the transmission providers expect a particular Long-Term Regional Transmission Facility to provide to transmission customers in the transmission planning region. As further discussed in the Regional Transmission Planning Cost Allocation section below, this final rule requires transmission providers to provide a forum for Relevant State Entities to negotiate a cost allocation method and/or a process for determining future cost allocation methods for

Long-Term Regional Transmission Facilities, which enables robust participation by those entities. Moreover, the cost allocation methods required by this final rule are intended to ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits that a Long-Term Regional Transmission Facility provides to transmission customers.

270. The benefits this rule requires to be used and measured—which provide an important source of transparency regarding any resulting allocation of costs to transmission customers—reflect objective, measurable changes in transmission system conditions, rather than achievement of state public policies. For example, even if a state's public policy is one driver of a Long-Term Transmission Need, these benefits of a Long-Term Regional Transmission Facility resolving that need are well understood and measurable, including, for example, reducing the cost of generating electricity by allowing for the increased dispatch of suppliers that have lower incremental costs of production, minimizing energy losses incurred in transmitting electricity, and lowering the number or duration of loss of load events. Transmission providers will evaluate Long-Term Regional Transmission Facilities for selection considering these benefits that these facilities would provide, and these benefits accrue to the transmission customers that fund their construction. In other words, under this final rule, customers pay for a more reliable and economic transmission system as identified through open and transparent Long-Term Regional Transmission Planning, and any state's ratepayers only fund the construction of Long-Term Regional Transmission Facilities that provide them

with such benefits that are at least roughly commensurate with the costs of those facilities.

271. We turn now to commenters' specific jurisdiction arguments. As an initial matter, we acknowledge that, in addition to granting authority to the Commission over the transmission of electric energy in interstate commerce, FPA section 201 also reserves certain authority to the states.[624] As such, we agree with Southern that Congress sought in enacting the FPA to ensure the "continued exercise of state power"[625] over certain matters. However, the requirements in this final rule respect and do not unlawfully infringe on state authority. Rather, as discussed above, the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes, which we conclude are unjust and unreasonable.

[624] *See* 16 U.S.C. 824(a)-(b)(1); *New York v. FERC*, 535 U.S. at 20-21 ("It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in [*Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927) (*Attleboro*)]. The FPA authorized federal regulation not only of wholesale sales that had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation. More importantly, as discussed above, the FPA authorized federal regulation of interstate *transmissions* as well as of interstate wholesale sales, and such transmissions were not of concern in *Attleboro*." (emphasis in original) (internal citations omitted)).

[625] Southern Initial Comments at 16 (quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. at 385).

272. We acknowledge that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable. Effective transmission planning necessarily involves taking into account assumptions about the generation resources that will be available, because transmission needs arise from the relative amounts, locations, and timing of supply (i.e., generation) and of demand (i.e., load); indeed, existing transmission planning processes also take into account these assumptions.[626] Our action in this final rule simply modifies the scope and duration of these assumptions to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis by requiring transmission providers to evaluate factors that give rise to Long-Term Transmission Needs.

273. Southern and SERTP Sponsors acknowledge that the NOPR proposed to require transmission providers to incorporate the results of state-sanctioned integrated resource planning as factors in developing Long-Term Scenarios, but they insist that Long-Term Regional Transmission Planning will intrude upon state authority if we do not require Long-Term Scenarios to be *limited* to those state-sanctioned resources.[627] This assertion is incorrect for at least three reasons. First, the public utilities whose integrated resource

[626] *See*, *e.g.*, Xcel Initial Comments at 13, 16 & n.26 (discussing generation resource assumptions made in existing Order No. 1000 regional transmission planning and cost allocation processes).

[627] SERTP Sponsors Initial Comments at 15-17; Southern Initial Comments at 18-19.

plans are approved by state commissions are not the only entities whose decisions may influence the development of generation resources within a particular transmission planning region. For example, a wide variety of private enterprises, publicly-owned utilities, and electric cooperatives have made commitments to fund the development of certain generation resources, and transmission providers may reasonably determine that these procurement decisions give rise to Long-Term Transmission Needs. Second, making generation resource assumptions for the purpose of performing transmission planning does not result in any legally-binding determination on a matter within a state's jurisdiction, let alone undermine a state's ability to ultimately decide what generation resources to build, and on what timetable.[628] Third, as Southern and SERTP Sponsors concede,[629] many existing integrated resource planning processes do not identify specific generation resources beyond a particular point in time. Other integrated resource planning processes may not result in a set of state-sanctioned generation resources and

[628] We disagree with Southern's and SERTP Sponsors' contention that the inclusion of such non-binding assumptions about generation resources in transmission planning will "bias" subsequent state resource decisions. *See* Southern Initial Comments at 19; SERTP Sponsors Initial Comments at 17 n.20. As Kentucky Commission Chair Chandler argues, the NOPR's reforms do not foreclose states' decision making on generation. Kentucky Commission Chair Chandler Reply Comments at 3. We also disagree with North Carolina Commission and Staff's contention that merely requiring transmission providers to use and measure production cost savings in evaluating Long-Term Regional Transmission Facilities "could conflict with state-jurisdictional resource decisions." North Carolina Commission and Staff Initial Comments at 7. If nothing else, Long-Term Regional Transmission Planning will provide public utilities and state commissions the opportunity to develop longer-term, forward-looking, robust assessments that can inform future decision making.

[629] SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 19.

may instead serve merely as a guide for the relevant public utility.[630] As a result, relying on such integrated resource planning processes exclusively to identify Long-Term Transmission Needs would fail to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis and therefore would fail to ensure just and reasonable Commission jurisdictional-rates. To be clear, we are not in this final rule attempting to denigrate or diminish the importance of integrated resource planning. Rather, in the context of Long-Term Regional Transmission Planning, integrated resource planning is reasonably considered one of several categories of factors used to develop Long-Term Scenarios and identify Long-Term Transmission Needs.

274. In that light, Southern's and SERTP Sponsors' argument—that we should limit transmission providers to state-approved resources and prohibit non-binding assumptions about the resource mix and demand—does not safeguard but in fact subverts the FPA's division between federal and state authority. As stated above, were we to require that transmission providers limit their assumptions to only state-sanctioned generation resources, we would be requiring transmission providers to ignore many of the factors that, as demonstrated by this record, transmission providers must reasonably consider to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, it is

[630] *See, e.g.*, SREA Reply Comments at 2-3 (arguing, in response to Alabama Commission, that Alabama has no formal integrated resource plan process upon which the Commission could encroach).

within our jurisdiction to determine the factors that transmission providers must incorporate in order to identify Long-Term Transmission Needs.

275. Commenters' arguments that the final rule would not withstand judicial scrutiny under the "major questions doctrine" are similarly unfounded. For example, some commenters appear to misinterpret *West Virginia v. EPA* as standing for the proposition that "the nation's energy policy and generation mix is a 'major question' and that an agency must have direct authorization from Congress to assert jurisdiction" over these matters.[631] As an initial matter, as noted above, the aim of this final rule is not to influence the generation mix or energy policy more broadly, but to ensure that Commission-jurisdictional transmission providers are planning for Long-Term Transmission Needs in a manner that is just and reasonable and results in just and reasonable Commission-jurisdictional rates.

276. In any case, the Court did not determine that energy policy and the mix of generation resources are *in every instance* a major question. Instead, in *West Virginia v. EPA*, the U.S. Supreme Court considered a specific agency action in light of a specific statutory provision and concluded that the Environmental Protection Agency's (EPA) exercise of authority was a "major question" based on a variety of factors specific to that context—including whether the EPA's administrative action was a "transformative"

[631] SERTP Sponsors Initial Comments at 17-18; Southern Initial Comments at 20; *see also* Undersigned States Reply Comments at 3 ("National-scale energy grid regulation is a 'major question' because of the massive economic consequences involved in such regulation.").

expansion of its power, whether the EPA had relevant technical and policy expertise, whether the relevant statutory provision was "ancillary" to the broader statutory construct, and whether the EPA's administrative action implicated significant economic and political questions.[632]

277. Commenters have not attempted a similar analysis of whether courts should construe this final rule as a "major question,"[633] and we find that their contentions that courts ought to do so are based on the factual mischaracterizations discussed above. In any event, this final rule neither transforms nor expands the Commission's authority; it merely applies existing authority, based on the Commission's expertise and experience, to identify and remedy deficiencies in existing regional transmission planning and cost allocation processes.[634] As with Order Nos. 890 and 1000, the Commission is promulgating a final rule pursuant to FPA section 206 to address those deficiencies in order to ensure that transmission planning practices, a subject long-regulated by the Commission and well within its area of expertise, remain just and reasonable and not unduly discriminatory or preferential. To that end, this final rule requires further reforms

[632] *West Virginia v. EPA*, 597 U.S. at 710, 724-725, 729, 731-32; *see also Biden v. Nebraska*, 143 S. Ct. 2355, 2372-2374 (2023) (applying *West Virginia v. EPA's* mode of analysis).

[633] *See* Harvard ELI and Policy Integrity Supplemental Comments at 2 (arguing that Undersigned States, for example, "overlook key requirements of the major questions doctrine").

[634] *See, e.g.*, *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 68-69. *Cf. PJM Power Providers Grp. v. FERC*, 88 F.4th at 274.

to regional transmission planning and cost allocation processes so that they are sufficiently long-term, forward-looking, and comprehensive. And while the transmission planning required in this final rule may be more forward-looking, long-term, and comprehensive than the status quo, as a matter of the Commission's jurisdiction, it is fundamentally no different than the regional transmission planning already required by the Commission and upheld by appellate courts.[635] In short, the differences in transmission planning required by this final rule represent differences in degree, not kind, from the Commission's longstanding regulations. As such, they are a far cry from the "transformative expansion" of the EPA's authority on which the Court relied in *West Virginia v. EPA* to find that the issue presented therein represented a major question not delegated to the agency to decide.

278. Just as it is clear that incremental improvements to practices that the courts have already determined fall squarely within the Commission's jurisdiction do not constitute a "transformative expansion" or "extraordinary grant" of regulatory authority to which the major questions doctrine may apply, so too is it clear that the other ancillary factors cited by the Court are similarly inapplicable. The final rule's incremental process improvements, while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the "vast economic and political significance" that would implicate the

[635] *See, e.g., S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 48-49; *see also* Harvard ELI and Policy Integrity Supplemental Comments at 4-7.

major questions doctrine.[636] The Commission's regulation of interstate transmission rates will have an effect on billions of dollars in customer charges and, in that generic sense, is of political interest to many. The incremental process improvements required by the final rule, however, do not fundamentally change the economic or political stakes of ensuring that Commission-jurisdictional rates remain just and reasonable.

279. Likewise, the Commission's continued assertion of authority over regional transmission planning and cost allocation processes does not resemble the EPA's assertion of authority related to the electric system that the Court found to be beyond that agency's expertise.[637] Here, the Commission undisputedly bears the relevant expertise over the interstate transmission system.[638] Nor does the Commission rely on a "backwater" statutory provision to achieve its reforms.[639] The Commission relies on FPA sections 205 and 206, which the Court has held "unambiguously authorize[]" the Commission to assert jurisdiction over interstate transmission[640] and extends an

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[636] *West Virginia v. EPA*, 597 U.S. at 735 (J. Gorsuch, concurring).

[637] *West Virginia v. EPA*, 597 U.S. at 729 (finding relevant that EPA itself admitted it lacked expertise to project "system-wide trends in areas such as electricity transmission, distribution, and storage").

[638] *Cf. Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 600-01 (D.C. Cir. 1997) ("[The Federal Energy Regulatory Commission] is entrusted with administering the regulations relating to oil pipelines and has an expertise in the field *based on that jurisdiction*." (emphasis added)).

[639] *West Virginia v. EPA*, 597 U.S. at 729.

[640] *New York v. FERC*, 535 U.S. at 19.

authority—indeed, a duty—to ensure that the practices directly affecting such rates are just and reasonable.[641] This provision was not ancillary to the statutory scheme but, rather, central to Congress' aim to ensure that the Commission possessed adequate authority to regulate interstate transmission beyond the reach of state power.[642] Finally, commenters do not point to Congress's "conspicuous[] and repeated[]" rejection of legislation that would enact reforms similar to those adopted in the final rule.[643]

280. We also disagree with Undersigned States' legal claim that allowing "one [s]tate [to] effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation" would violate the Constitution's "equal sovereignty doctrine."[644] As discussed above, the final rule categorically does not require states to subsidize other states' public policies or generation decisions. To the contrary, consistent with the cost causation principle, this final rule requires customers to pay for a share of the costs of new Long-Term Regional Transmission Facilities only to the extent that *they* benefit from those facilities and, even then, any share they pay for must be roughly commensurate with the benefits they receive.[645]

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[641] *EPSA*, 577 U.S. at 277.

[642] *New York v. FERC*, 535 U.S. at 20-21 (discussing enactment of FPA in 1935 as a response to *Attleboro*).

[643] *West Virginia v. EPA*, 597 U.S. at 745 (J. Gorsuch, concurring).

[644] Undersigned States Reply Comments at 5-6.

[645] *See supra* note 623 and accompanying discussion.

281. Moreover, according to Undersigned States, the equal sovereignty doctrine dictates that the nation "is a union of [s]tates, equal in power, dignity and authority, each competent to exert that residuum of sovereignty not delegated to the United States by the Constitution itself."[646] But, "neither the Supreme Court nor any other court has ever applied that principle as a limit on the Commerce Clause or other Article I powers."[647] Instead, Courts have found that "the Constitution does not contain any textual provision suggesting an equal sovereignty limit on Congress's Article I powers generally or on the Commerce Clause in particular."[648] As relevant here, pursuant to the Constitution's Commerce Clause,[649] Congress duly enacted the FPA, which in turn empowers the Commission to regulate the rates and practices affecting rates for the transmission of electricity in interstate commerce.[650] Under the FPA, the Commission is "unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus . . . ."[651]

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[646] Undersigned States Reply Comments at 5 (citing *Coyle v. Smith*, 221 U.S.at 567 ). *But see Ohio v. EPA*¸ 2024 WL 1515001, at *15 (D.C. Cir. Apr. 9, 2024) (holding that "[t]he equal footing cases," like *Coyle v. Smith*, "do not directly apply either outside of the admission context or to Article I powers like the Commerce Clause.").

[647] *Ohio v. EPA*, 2024 WL 1515001 at *13.

[648] *Id.* at *16.

[649] U.S. Const. art. 1, 8.

[650] 16 U.S.C. 824d.

[651] *PJM Power Providers Grp. v. FERC*, 88 F.4th at 275; *see also Elec. Power Supply Ass'n v. Star*, 904 F.3d at 524 (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois "as givens and set out to make the

282. The nature of the interconnected transmission system is such that states naturally affect one another in pursuing policies available to them while exercising the authority reserved to them under FPA section 201.[652] For the reasons explained in this final rule, we conclude that transmission providers must participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, and we find that transmission providers must have the opportunity to select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Our role within our federal system is not to "unreasonably interfere with" nor to "pass judgement on state and local policies and objectives,"[653] including where such policies and objectives have incidental interstate effects.[654] Nor need we, because even if one state's public policy is a driver of a Long-Term Transmission Need,

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best of the situation [these systems] produce").

[652] *See Elec. Power Supply Ass'n v. Star*, 904 F.3d at 524 (describing the effects on interstate sales resulting from states' exercise of powers reserved to them under FPA section 201 as "an inevitable consequence of a system in which power is shared between state and national governments" (citing *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 164 (2016)).

[653] *N.J. Bd. Pub. Utils. v. FERC*, 744 F.3d 74, 98 n.24 (3rd Cir. 2014) (quoting *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 3 (2011)); *see also PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080, at P 186 (2024) (rejecting an argument that the Commission was required to determine whether state-sponsored resources were providing disproportionate benefits to other states in the form of lower capacity market prices).

[654] *See Coal. for Competitive Elec. v. Zibelman*, 906 F.3d 41, 56 (2d Cir. 2018) (collecting Commission orders sanctioning state-jurisdictional programs incidentally affecting wholesale markets).

the costs of a Long-Term Regional Transmission Facility that transmission providers select will be allocated to transmission customers only to the extent that they benefit from that facility and only to a degree that is at least roughly commensurate with the benefits that facility provides to them. That approach is consistent with Commission precedent and commenters have not demonstrated that this framework results in impermissible cross-subsidization among states.[655]

283. Finally, in response to NRECA's request, we confirm that the final rule is consistent with the Commission's obligation under FPA section 217(b)(4). As articulated in *South Carolina Public Service Authority v. FERC*, FPA section 217(b)(4) requires the Commission to "facilitate the planning of a reliable grid," and we do so by "seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations."[656] This final rule seeks to ensure precisely the same goal, and it therefore satisfies the Commission's obligation under FPA section 217(b)(4).

[655] For example, PJM incorporates transmission needs driven by Public Policy Requirements into the assumptions stage of its regional transmission planning process to identify needed reliability and economic regional transmission facilities for potential selection and cost allocation, rather than through a separate and distinct process to identify and allocate the costs of transmission facilities selected to address transmission needs driven by Public Policy Requirements. The Commission found PJM's approach complied with the requirement in Order No. 1000 to consider transmission needs driven by Public Policy Requirements in regional transmission planning and cost allocation processes. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 109-120 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128, at PP 66-71 (2014).

[656] 762 F.3d at 90.

### B. Development of Long-Term Scenarios

#### 1. NOPR Proposal

284. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission proposed to define Long-Term Scenarios as a tool to identify the transmission planning region's needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. The Commission explained that a scenario is a hypothetical sequence of events that includes assumptions used to forecast transmission needs. The Commission also stated that assumptions used to forecast transmission needs driven by changes in the resource mix and demand include: forecasts of the level and pattern (i.e., hourly and seasonal variability) of future electricity demand; the quantity, location, and type of resource additions and retirements; and other relevant forecasts about the electric power system that are used as inputs to the transmission model and determine the need for new transmission facilities over the transmission planning horizon. In addition, the Commission noted that other relevant assumptions might include forecasts for natural gas prices, increasing outage trends due to extreme weather and climatic trends, and other future events.

285. The Commission also proposed in the NOPR to require that transmission providers use Long-Term Scenarios to evaluate potential regional transmission facilities

needed to meet transmission needs driven by changes in the resource mix and demand to identify the more efficient or cost-effective regional transmission facilities.[657]

### 2. Comments

#### a. General Comments

286. Of the commenters specifically addressing the proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning, the majority support scenario-based planning.[658] Clean Energy Buyers state that Long-Term Scenarios are critical to Long-Term Regional Transmission Planning because its success will depend on the quality of forecasting.[659] Form Energy states that long-term scenario review will ensure that transmission upgrades address future needs in a cost-effective and environmentally friendly manner.[660] LADWP asserts that Long-Term Scenarios are critical to developing

[657] NOPR, 179 FERC ¶ 61,028 at P 84.

[658] *See* ACEG Initial Comments at 6; AEP Initial Comments at 7-8; Amazon Initial Comments at 2-3; BP Initial Comments at 4; California Commission Initial Comments at 1-2, 5-6, 21; California Energy Commission Initial Comments at 1-2; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 11; Duke Initial Comments at 10; Eversource Initial Comments at 10; Exelon Initial Comments at 5; Form Energy Initial Comments at 2-3; GridLab Initial Comments at 10; Handy Law Initial Comments at 9-10; Indicated PJM TOs Initial Comments at 7-8; LADWP Initial Comments at 2; NARUC Initial Comments at 4; National Grid Initial Comments at 10-11; PIOs Initial Comments at 14; PPL Initial Comments at 4; SEIA Initial Comments at 4-5; Southeast PIOs Initial Comments at 42; SREA Initial Comments at 39; State Agencies Initial Comments at 14; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 2; WE ACT Initial Comments at 3; WIRES Initial Comments at 6.

[659] Clean Energy Buyers Initial Comments at 11.

[660] Form Energy Initial Comments at 3.

an effective transmission system that ensures reliability, while also providing flexibility to support the delivery of renewable energy.[661] NARUC states that Long-Term Scenarios are a flexible planning tool for addressing the uncertainty involved in identifying transmission needs driven by changes in the resource mix and demand and that using them will ensure that transmission providers adequately assess the potential benefits of regional transmission facilities.[662]

287. Southeast PIOs claim that Long-Term Scenarios are essential to improving current transmission planning processes in the Southeast.[663] SREA argues that Long-Term Regional Transmission Planning is not occurring in MISO South and states that scenario planning is contentious but necessary.[664]

288. California Energy Commission requests that the Commission clarify that transmission providers may rely on scenarios developed by other agencies, as currently CAISO relies on analyses conducted by California Energy Commission and California Commission.[665] Relatedly, New York Commission and NYSERDA and ISO-NE highlight the importance of state-led identification of public policy needs and their impact

[661] LADWP Initial Comments at 2.

[662] NARUC Initial Comments at 4.

[663] Southeast PIOs Initial Comments at 42, 46.

[664] SREA Initial Comments at 39-41.

[665] California Energy Commission Initial Comments at 2.

on scenario assumptions.[666] New York Commission and NYSERDA state that, especially in a single-state RTO/ISO like NYISO, the state should be afforded a central role in determining the scenarios to be studied.[667] ISO-NE also believes that reliance on states is consistent with prior Commission orders permitting transmission providers to rely on a committee of state regulators to identify transmission needs driven by Public Policy Requirements.[668]

289. PJM States suggest that the Commission's proposal for state involvement in the development of Long-Term Scenarios could be interpreted as more limited than its proposal for state involvement with respect to Long-Term Regional Cost Allocation and ask that the Commission clarify that retail regulators have a primary role in both. PJM States warn that, if a retail regulator disagrees with the scenarios or benefits metrics used to select a transmission project, it is unlikely to receive regulatory approval.[669]

290. Cypress Creek asserts that the Commission should require the use of a defined and standardized set of baseline assumptions to ensure that scenario projections are realistic,

[666] New York Commission and NYSERDA Initial Comments at 7; ISO-NE Initial Comments at 25-26.

[667] New York Commission and NYSERDA Initial Comments at 8.

[668] ISO-NE Initial Comments at 25 (citing *ISO New England Inc.*, 143 FERC ¶ 61,150, at P 108 (2013)).

[669] PJM States Initial Comments at 3-4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

and that deviation should only be allowed if the proposal is consistent with or superior to the *pro forma*.[670]

291. Concerned Scientists state that the Commission should reject comments arguing that uncertainty prohibits scenario-based planning, and instead endeavor to create a transmission planning process that properly acknowledges and addresses that uncertainty. Concerned Scientists state that uncertainty does not prohibit long-term transmission planning but rather necessitates the evaluation of multiple plausible scenarios to identify investments that will perform well over a variety of possible future conditions. Concerned Scientists explain that, just as utilities and generator developers do not shy away from an uncertain future when building new generation resources, transmission investments should also be informed by, but not avoided due to, future uncertainty. Concerned Scientists state that the Commission's proposed Long-Term Scenarios requirements are a reasonable minimum for responsible transmission planning.[671]

292. Other commenters support the NOPR proposal to require Long-Term Scenarios in transmission planning but have reservations.[672] Many of these commenters argue that the NOPR is too prescriptive and ask for greater flexibility so that the Long-Term Scenario

[670] Cypress Creek Reply Comments at 5-8.

[671] Concerned Scientists Reply Comments at 18-19.

[672] Ameren Initial Comments at 7-8; American Municipal Power Initial Comments at 7; APPA Initial Comments at 25; CAISO Initial Comments at 21; Chemistry Council Initial Comments at 5; Michigan Commission Initial Comments at 4-5; MISO TOs Initial Comments at 15-17; Omaha Public Power Initial Comments at 3-4; OMS Initial Comments at 3-5; PJM Initial Comments at 54.

planning already occurring in their respective transmission planning region will comply with any final rule.[673] For example, OMS points to such flexibility as key to the success of MISO's long-term transmission planning processes.[674] SERTP Sponsors argue that the Commission should not make Long-Term Scenarios even more prescriptive because such an approach would likely result in litigation and delay.[675]

293. American Municipal Power believes that transmission providers should conduct Long-Term Scenarios in a highly collaborative way with the full and active participation of all stakeholders.[676] Similarly, Six Cities recommend that Long-Term Scenarios be coordinated between state and local regulatory authorities to reflect varying policies. Six Cities recommend that, in CAISO, Long-Term Scenarios should consider the procurement choices of non-jurisdictional utilities, such as Six Cities, as well as policy portfolios provided by California Commission.[677]

294. Some commenters oppose the NOPR proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning.[678] Dominion argues for maximum

[673] CAISO Initial Comments at 21; Michigan Commission Initial Comments at 4-5; MISO TOs Initial Comments at 15-16; OMS Initial Comments at 3-4.

[674] OMS Initial Comments at 4-5.

[675] SERTP Sponsors Reply Comments at 13-14.

[676] American Municipal Power Initial Comments at 7.

[677] Six Cities Initial Comments at 4.

[678] Dominion Initial Comments at 10; Idaho Commission Initial Comments at 3; Nebraska Commission Initial Comments at 3; Ohio Consumers Initial Comments at 2, 5; Potomac Economics Initial Comments at 2.

flexibility for planning assumptions to support reliable and affordable transmission service for customers.[679] Idaho Commission states that any prescription for scenario analysis should be supported by clear evidence of a deficiency.[680] Instead of specific scenario planning requirements, Nebraska Commission states that the Commission should provide general guidelines and as much flexibility as possible to transmission providers, who—along with state regulatory officials—are best situated to evaluate the needs of each transmission planning region.[681]

295. Potomac Economics questions the NOPR's proposal to require Long-Term Scenarios, stating that it will force RTOs/ISOs to plan and commit to sizable transmission investment costs based on uncertain factors and unreasonable speculation on factors such as the location of future generation, retirements, grid enhancing technologies, and transmission reconfiguration options.[682] Potomac Economics also questions the usefulness of Long-Term Scenarios, asserting that future congestion patterns will be increasingly uncertain given that the higher penetration of intermittent resources will cause larger fluctuations in transmission flows, making it more difficult to accurately estimate the benefits of transmission upgrades.[683] Potomac Economics argues that many

[679] Dominion Initial Comments at 10-12.

[680] Idaho Commission Initial Comments at 3.

[681] Nebraska Commission Initial Comments at 3.

[682] Potomac Economics Initial Comments at 2, 4.

[683] *Id*. at 2.

of the most beneficial transmission upgrades address very specific constraints, are smaller in size, can be difficult to identify in advance, and can be very sensitive to modest changes in generation and load.[684]

### b. Applying Scenario Planning to Reliability and Economic Planning

296. California Commission and City of New York assert that the Commission should require the use of Long-Term Scenarios in all transmission planning processes—not just Long-Term Regional Transmission Planning.[685] City of New York argues that such a requirement would enable consideration of a broad range of potential future system conditions across multiple planning categories.[686] Similarly, NYISO states that the final rule should authorize, but not require, the use of multiple alternative scenarios in existing transmission planning processes. NYISO states that doing so would enhance its ability to anticipate and solicit more efficient, holistic transmission solutions, which would support system reliability and resilience.[687]

297. In contrast, certain commenters oppose requiring transmission providers to incorporate some form of scenario analysis into their existing reliability and economic

[684] *Id*. at 3.

[685] California Commission Initial Comments at 22-24; City of New York Initial Comments at 7.

[686] City of New York Initial Comments at 7.

[687] NYISO Initial Comments at 14-15.

regional transmission planning processes.[688] Duke contends that the Commission should avoid disrupting existing regional transmission planning processes that work well.[689] MISO notes that, while this type of scenario-based planning has been applied to economic transmission planning processes and could be applied to existing reliability transmission planning processes, such application should be flexible and tailored to the unique needs of each transmission provider, adding that scenario-based planning requires considerable time and resources.[690]

### 3. Commission Determination

298. We adopt, with modification, the NOPR proposals to require transmission providers in each transmission planning region to (1) develop and use Long-Term Scenarios as part of Long-Term Regional Transmission Planning and (2) use those Long-Term Scenarios to identify and evaluate Long-Term Regional Transmission Facilities needed to meet Long-Term Transmission Needs. As further explained in subsequent sections of this final rule, we find that these requirements regarding the development and use of Long-Term Scenarios in Long-Term Regional Transmission Planning strike a reasonable balance between ensuring that Long-Term Regional Transmission Planning reasonably identifies Long-Term Transmission Needs over a sufficiently long-term,

[688] Duke Initial Comments at 2, 10-11; Eversource Initial Comments at 19; MISO Initial Comments at 32; NESCOE Initial Comments at 23; PJM Initial Comments at 54-56.

[689] Duke Initial Comments at 2, 10-11.

[690] MISO Initial Comments at 32.

forward-looking transmission planning horizon and providing sufficient flexibility for transmission providers to develop and use Long-Term Scenarios in a way that reflects the unique characteristics of their respective transmission planning regions.

299. We first address the definition of Long-Term Transmission Needs. For purposes of this final rule, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors. As explained in the NOPR, the drivers of transmission needs are diverse and include, but are not limited to, evolving reliability concerns, changes in the resource mix, and changes in demand. For example, as identified in the NOPR, reliability concerns giving rise to Long-Term Transmission Needs include, among other things, the increasing frequency of high-impact extreme weather events, the increasing reliance by transmission system operators on regional integration and coordination to reliably serve load, the operational challenges created by the increasing share of variable resources entering the resource mix, and changes in electric demand patterns such as shifts in load profiles caused by, for example, the emergence of large loads associated with evolving industrial and commercial needs such as the growth in data centers, and increased electrification of energy end uses.[691]

300. In the NOPR, the Commission referred to transmission needs identified through Long-Term Regional Transmission Planning largely as needs driven by changes in the

[691] *See* NOPR, 179 FERC ¶ 61,028 at PP 45, 51.

resource mix and demand.[692] Nevertheless, we agree with commenters who correctly note that there are additional drivers of Long-Term Transmission Needs,[693] and, as noted above, the Commission itself contemplated in the NOPR that Long-Term Regional Transmission Planning would consider drivers beyond those tied directly to changes in supply and demand. We therefore clarify that, although changes in the resource mix and demand are important drivers of Long-Term Transmission Needs, they represent only a subset of such drivers. In addition, we note that Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000. Where Long-Term Transmission Needs differ is their identification through the long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes established in this final rule. Accordingly, in this final rule, we refer to the transmission needs that are identified through Long-Term Regional Transmission Planning as Long-Term

[692] *Id*.

[693] *See, e.g.*, AEE Initial Comments at 7-8 (noting that reforms are needed to meet transmission needs driven by "market forces, state policies, and new reliability and resilience imperatives"); ELCON Initial Comments at 4 ("[L]ong term scenario planning should not be limited to anticipated resource mix but also take into consideration impacts on reliability and congestion management."); New Jersey Commission Initial Comments at 2 ("[T]he Board stresses that most of the reforms the Commission is proposing would be necessary even in the absence of 'changes in the resource mix and demand.'") (citing NOPR, 179 FERC ¶ 61,028 at P 24); Renewable Northwest Initial Comments at 8 (noting how current transmission planning processes ignore both "trends in future generation and the impact of extreme weather events") (citing NOPR, 179 FERC ¶ 61,028 at P 51); Southeast PIOs Initial Comments at 7-8 (noting that both intensifying "changes in the generation mix" and "increasingly common extreme weather and high-intensity, low frequency events" burden the existing transmission system).

Transmission Needs. The identification of Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to potentially meet those needs is accomplished through the use of Long-Term Scenarios in Long-Term Regional Transmission Planning.

301. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section of this final rule, we require transmission providers to measure and use a set of seven required benefits in Long-Term Regional Transmission Planning. Transmission providers must use this same set of benefits to help to inform their identification of Long-Term Transmission Needs. For example, in this final rule we require transmission providers to measure and use production cost savings in Long-Term Regional Transmission Planning. As such, when transmission providers are working to identify Long-Term Transmission Needs, areas of significant congestion on the transmission system—where Long-Term Regional Transmission Facilities could reduce congestion and in turn facilitate production cost savings—may indicate a Long-Term Transmission Need.

302. We adopt the definition of Long-Term Scenarios proposed in the NOPR,[694] with modification. We define Long-Term Scenarios as scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a

[694] In the NOPR, the Commission proposed to define Long-Term Scenarios as a tool to identify transmission needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. NOPR, 179 FERC ¶ 61,028 at P 84.

sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs. We make this modification to clarify the intent of the definition proposed in the NOPR, rather than modify the definition in substance.

303. Certain commenters assert that the Commission should not require transmission providers to develop Long-Term Scenarios due to the inherent uncertainty of forecasting future transmission needs over a long transmission planning horizon. We acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs. However, we believe that such uncertainty is mitigated by using Long-Term Scenarios themselves, as noted by Concerned Scientists and NARUC.[695] Scenario planning allows transmission providers to evaluate whether Long-Term Regional Transmission Facilities are beneficial in more than one scenario. Transmission providers may also examine whether Long-Term Transmission Needs appear in one or more scenarios. Scenario planning also allows transmission providers to consider a broader range of future circumstances and be better prepared for changes in the electric power system.[696] Finally, transmission providers may use scenario planning to determine whether identified Long-Term Regional Transmission Facilities provide sufficient benefits across more than one

[695] Concerned Scientists Reply Comments at 18-19; NARUC Initial Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 86, 88).

[696] *See* Policy Integrity Reply Comments at 2.

scenario when considering whether to select such facilities, as also noted by NARUC.[697] Moreover, we adopt requirements for Long-Term Scenarios, as discussed further below, to ensure they are based on reasonable assumptions and better reflect future transmission system conditions and uncertainties in those future circumstances. In sum, incorporating Long-Term Scenarios into Long-Term Regional Transmission Planning provides an appropriate approach to ensure just and reasonable rates by accounting for the increasing uncertainty in the accuracy of assumptions over longer (i.e., over 10 years) transmission planning horizons and mitigating the risks of under-building or over-building Long-Term Regional Transmission Facilities.

304. Further, we disagree with commenters that suggest that the Commission should not establish specific Long-Term Scenario requirements and that imposing general principles is sufficient to ensure just and reasonable rates. We find that Long-Term Regional Transmission Planning that does not incorporate Long-Term Scenarios that meet the requirements of this final rule would fail to ensure that transmission providers identify Long-Term Transmission Needs, as well as identify and evaluate Long-Term Regional Transmission Facilities to address those needs. For example, relying on a single forecast of future transmission system conditions may limit transmission providers' and stakeholders' confidence in identified Long-Term Transmission Needs, and accordingly the evaluation of Long-Term Regional Transmission Facilities to address those needs. Further, failure to incorporate Long-Term Scenarios would increase the

[697] NARUC Initial Comments at 4.

likelihood of piecemeal and relatively inefficient or less cost-effective transmission development. Accordingly, we find that requiring transmission providers to develop and use Long-Term Scenarios that meet the requirements established in this final rule as part of Long-Term Regional Transmission Planning will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

305. Additionally, as stated above and in response to commenters that emphasize the importance of collaboration in developing Long-Term Scenarios, this final rule retains the requirements for an open, coordinated, and transparent local transmission planning process established in Order No. 890 and further required for regional transmission planning in Order No. 1000.[698] For example, consistent with the transparency transmission planning principle,[699] transmission providers must make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario. Moreover, as described below, this final rule requires that transmission providers provide meaningful opportunity for stakeholder input, including from state and local regulators, as well as non-jurisdictional entities, into the factors used to develop Long-Term Scenarios.

306. In response to PJM's request that the Commission clarify that the role of the state regulator is primary in developing Long-Term Scenarios, we note that, as described in the

[698] Order No. 1000, 136 FERC ¶ 61,051 at PP 150-152; Order No. 890, 118 FERC ¶ 61,119 at P 435.

[699] Order No. 890, 118 FERC ¶ 61,119 at P 471.

Stakeholder Process and Transparency determination within the Categories of Factors section, transmission providers retain the ultimate responsibility for transmission planning.[700] As such, transmission providers have discretion, subject to the limits imposed in this final rule, to weigh more heavily one source of information over another, such as weighing information related to a factor provided by a state regulator more heavily than information provided by other stakeholders. In response to California Energy Commission, we find that the final rule does not preclude transmission providers from relying on scenarios developed by state agencies, provided that the Commission finds that the OATT provisions governing those Long-Term Scenarios' development comply with the Long-Term Scenarios requirements of this final rule (e.g., transmission planning horizon and stakeholder input requirements). We decline to require the use of Long-Term Scenarios in all transmission planning processes, as requested by California Commission and City of New York. The record in this proceeding does not demonstrate that the incorporation of Long-Term Scenarios in existing Order No. 1000 regional transmission planning processes is necessary to ensure that Long-Term Regional Transmission Planning is just and reasonable. In response to NYISO's request that

[700] *Id*. P 454 ("In response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarify that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in this [f]inal [r]ule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.").

transmission providers be allowed to use scenario planning in their existing Order No. 1000 regional transmission planning processes, while we agree that such a practice may offer benefits, we find that any such request amending existing transmission planning processes must be submitted in an FPA section 205 filing separate from their compliance filings to this final rule.[701]

### C. Long-Term Scenarios Requirements

#### 1. Transmission Planning Horizon

##### a. NOPR Proposal

307. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[702]

308. The Commission preliminarily found that a 20-year transmission planning horizon requirement strikes a reasonable balance between the current transmission planning horizons used in many transmission planning regions and the 30-year or longer transmission planning horizon proposed by some ANOPR commenters. The Commission noted that the 30-year or longer transmission planning horizon was criticized by other commenters as speculative or too uncertain. The Commission also

[701] We note that an exception to the requirement to file a separate FPA section 205 filing applies if transmission providers were to propose a unified transmission planning process, as discussed above. *See supra* Participation in Long-Term Regional Transmission Planning section.

[702] NOPR, 179 FERC ¶ 61,028 at PP 97-100.

stated that a 20-year transmission planning horizon requirement may be reasonable because some transmission providers use a 20-year transmission planning horizon in existing regional transmission planning processes. In addition, the Commission stated that a 20-year transmission planning horizon would allow for sufficient time to identify, plan, and obtain siting and permitting approval for and to construct regional transmission facilities to meet long-term regional transmission needs, including those that may take longer than the average amount of time to go from the planning stage to in-service. Finally, the Commission stated that a 20-year transmission planning horizon would allow transmission providers to better leverage economies of scale by sizing transmission facilities to meet not only nearer-term transmission needs, but also longer-term transmission needs driven by changes in the resource mix and demand over time. The Commission preliminarily found that by assessing transmission needs over a longer time horizon—for example, starting in year six[703] through year 20 of the transmission planning horizon—Long-Term Regional Transmission Planning should be able to identify more efficient or cost-effective regional transmission facilities to address these needs.[704]

[703] The Commission noted that the North American Electric Reliability Corporation defines the long-term transmission planning horizon as covering year six through year 10 and beyond. *Id.* P 94 n.160.

[704] *Id.* PP 97-99 (footnotes omitted).

**b. Comments**

**i. Support for 20-Year Transmission Planning Horizon**

309. Many commenters support the Commission's proposal to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[705] Several commenters generally consider a 20-year transmission planning horizon to be reasonable,

[705] ACORE Initial Comments at 1; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8; AEP Initial Comments at 5, 8-12; Amazon Initial Comments at 2-3; BP Initial Comments at 4-5; Breakthrough Energy Initial Comments at 12-13; Breakthrough Energy Supplemental Comments at 1; California Water Initial Comments at 14-15; Certain TDUs Initial Comments at 3, 19; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 12; Clean Energy States Initial Comments at 2; Concerned Scientists Reply Comments at 18-19; Cypress Creek Reply Comments at 4; DC and MD Offices of People's Counsel Initial Comments at 8; Environmental Groups Supplemental Comments at 2; Eversource Initial Comments at 14; Form Energy Initial Comments at 2; Georgia Commission Initial Comments at 2-3; GridLab Initial Comments at 5; Idaho Power Initial Comments at 4; Illinois Commission Initial Comments at 6; Indicated US Senators and Representatives Initial Comments at 1; Interwest Initial Comments at 4-5; ITC Initial Comments at 9-11; LADWP Initial Comments at 2; Minnesota State Entities Initial Comments at 4; National and State Conservation Organizations Initial Comments at 1; National Grid Initial Comments at 12-13; Nevada Commission Initial Comments at 7; New England for Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 9-10; NextEra Initial Comments at 62; NYISO Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 2; PG&E Initial Comments at 2; Policy Integrity Initial Comments at 10; PIOs Initial Comments at 15; R Street Initial Comments at 6; SEIA Initial Comments at 6; SoCal Edison Initial Comments at 11-12; Southeast PIOs Initial Comments at 43; SPP Initial Comments at 5-6; SPP Market Monitor Initial Comments at 4-5; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments at 2); US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 10; Vermont Electric and Vermont Transco Initial Comments at 2; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

acceptable, or appropriate.[706] Some commenters argue that a 20-year transmission planning horizon provides a reasonable balance between shorter- and longer-term transmission planning horizons.[707] National Grid states that a 20-year transmission planning horizon balances the benefits of prospective transmission planning with the greater uncertainty that comes with forecasting system needs over a longer period.[708] Numerous commenters argue that a 20-year transmission planning horizon will help to improve the efficiency and cost of developing transmission and to assess future transmission needs.[709]

310. New Jersey Commission argues that a 20-year transmission planning horizon should help to make long-term multi-driver transmission projects viable by identifying needs and opportunities in a timeframe that allows states to have a meaningful conversation about voluntarily funding such projects.[710] Policy Integrity argues that it is crucial to model what is going to be needed *over* the next 20 years to ensure that short-

[706] CAISO Initial Comments at 21; EEI Initial Comments at 11; Entergy Initial Comments at 9; NARUC Initial Comments at 5; New York TOs Initial Comments at 10; Pine Gate Initial Comments at 19-20; PPL Initial Comments at 6; WIRES Initial Comments at 7.

[707] DC and MD Offices of People's Counsel Initial Comments at 8-9; LADWP Initial Comments at 2-3; National Grid Initial Comments at 12-13.

[708] National Grid Initial Comments at 12-13.

[709] AEP Reply Comments at 4-5 (citing MTEP2017 Review at 33-34); Amazon Initial Comments at 2-3; BP Initial Comments at 5; Certain TDUs Reply Comments at 5; PIOs Initial Comments at 15.

[710] New Jersey Commission Initial Comments at 9-10, 28.

and medium-term transmission projects are built efficiently, stating that a longer transmission planning horizon is reasonable in the context of long-lived transmission assets with long lead times.[711]

311. US DOE asserts that there is sufficient evidence to extend the transmission planning horizon to a minimum of 20 years for Long-Term Regional Transmission Planning to capture power sector changes that occur during transmission development.[712] PIOs note that panelists at the November 2021 Technical Conference suggested a 20-year transmission planning horizon is necessary, in part, due to long-term public policy goals.[713] Acadia Center and CLF similarly argue that transmission planners should plan over long-term horizons to factor in predictable trends, such as timelines required under state laws and policies.[714]

312. Several commenters emphasize that a transmission planning horizon of 20 years is sufficient to account for the amount of time needed to develop transmission projects, considering the complexity and challenges of major transmission development.[715] Eversource states that a long-term perspective is necessary to take advantage of the

[711] Policy Integrity Initial Comments at 10.

[712] US DOE Initial Comments at 10.

[713] PIOs Initial Comments at 15 (citing Tr. 129-137 (multiple witnesses)).

[714] Acadia Center and CLF Initial Comments at 4.

[715] Eversource Initial Comments at 14; Illinois Commission Initial Comments at 6; LADWP Initial Comments at 2; NextEra Initial Comments at 62-63; PG&E Initial Comments at 2; PIOs Initial Comments at 15.

economies of scale that large transmission projects can enable, as well as to incorporate anticipated changes in generation and load beyond the traditional transmission planning horizon.[716] Illinois Commission states that a 20-year transmission planning horizon is necessary to properly plan and build transmission and generation resources.[717] LADWP states that a 20-year transmission planning horizon provides enough time for transmission projects to be developed and placed in service when such projects require new rights-of-way without becoming too speculative.[718] NextEra contends that a 20-year transmission planning horizon will ensure that transmission planners anticipate and plan transmission facilities for needs driven by changes in the resource mix and demand.[719]

313. PIOs state that a 20-year transmission planning horizon should be the minimum timeframe, explaining that because transmission facilities can take 15 years to plan, permit, and construct, a 20-year transmission planning horizon can result in just-in-time planning, where the transmission plan is developed shortly before the process for siting and permitting must begin.[720] GridLab asserts that a 20-year transmission planning horizon might identify regional transmission needs that occur after year 10, as well as

[716] Eversource Initial Comments at 14.

[717] Illinois Commission Initial Comments at 6.

[718] LADWP Initial Comments at 2.

[719] NextEra Initial Comments at 62-63.

[720] PIOs Initial Comments at 15.

transmission projects that would be selected and approved in later transmission planning cycles.[721]

314. Clean Energy States support quick adoption of at least a 20-year planning horizon because many of their member states have established 100% clean energy power sector or zero-carbon goals for their state economies by 2040 or 2050.[722] California Municipal Utilities, on the other hand, support a 20-year transmission planning horizon, but caution that transmission costs identified can be significant and could rely upon speculative resources that may not come to fruition, namely off-shore wind development.[723]

315. Many commenters highlight transmission planning regions with existing long-term transmission planning that either does or will conform to the 20-year transmission planning horizon proposed in the NOPR.[724] MISO commits to continue using its 20-year forecast period under this proposed reform.[725] SPP states that it currently performs a 20-

[721] GridLab Initial Comments at 8-9.

[722] Clean Energy States Initial Comments at 2.

[723] California Municipal Utilities Initial Comments at 6-7.

[724] Acadia and CLF Initial Comments at 3; CAISO Initial Comments at 15; California Municipal Utilities Initial Comments at 5-6; Clean Energy States Initial Comments at 2; ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 33; MISO TOs Initial Comments at 17; New York TOs Initial Comments at 2; New York Transco Initial Comments at 5; NextEra Initial Comments at 63-64 (discussing efforts at CAISO, SPP, and MISO); Omaha Public Power Initial Comments at 4; PIOs Initial Comments at 14 (pointing to NYISO and MISO as examples of transmission planning regions already successfully using a 20-year transmission planning horizon); SPP Initial Comments at 5-6.

[725] MISO Initial Comments at 33.

year assessment that incorporates Long-Term Scenarios at least once every five years.[726] New York Transco notes that NYISO's transmission planning process utilizes multiple cases and scenarios over a 20-year evaluation horizon.[727] Acadia Center and CLF note that ISO-NE recently gained Commission approval for longer-term transmission studies to undertake long-term transmission planning to 2050.[728]

316. CAISO states that it currently approves transmission projects in its annual transmission planning process based on a 10-year outlook, although the CAISO OATT allows for a longer 20-year transmission horizon outlook to reliably and cost-effectively account for California's greenhouse gas and renewable energy objectives.[729] CAISO explains that its 20-year outlook does not include a process for approving specific transmission projects, but rather allows considerations beyond 10 years to inform decisions in its annual transmission planning process.[730] California Municipal Utilities also highlight CAISO's existing transmission planning processes, noting that its 20-year transmission outlook calls for an estimated combined capital cost of $30.5 billion.[731]

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[726] SPP Initial Comments at 5-6.

[727] New York Transco Initial Comments at 5 (citing NYISO, NYISO Tariffs, NYISO OATT, attach. Y § 31.4a (Public Policy Requirements Planning Process) (23.0.0), § 31.4.6.1).

[728] Acadia Center and CLF Initial Comments at 3.

[729] CAISO Initial Comments at 15.

[730] *Id*. at 15-16.

[731] California Municipal Utilities Initial Comments at 5-6 (citing CAISO, *20-Year Transmission Outlook*, Table ES-1: Cost estimate of transmission development to

NextEra notes that, while many transmission planning regions use or will use a 20-year transmission planning horizon, no requirements exist to ensure that these practices persist.[732]

317. Several commenters reference existing long-term planning processes as support for the Commission's proposed 20-year transmission planning horizon.[733] NextEra and ACEG explain that longer time horizons are embedded into existing integrated resource plans, through law or common practice, and extend into and beyond 2040 to meet ambitious resource goals.[734] R Street argues that, for benchmarking purposes, 20- to 25-year planning horizons have been a best practice for integrated resource planning for decades.[735]

integrate resources of SB100 Starting Point scenario (Jan. 31, 2022), http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf).

[732] NextEra Initial Comments at 64-65.

[733] BP Initial Comments at 5 (citing CAISO's transmission planning process); Idaho Power Initial Comments at 4 (noting NorthernGrid's 20-year transmission planning horizon); Interwest Initial Comments at 5 (noting existing state resource planning processes); Nevada Commission Initial Comments at 7 (noting its integrated resource planning process requiring a minimum of eight years); PIOs Initial Comments at 14 (noting 20-year horizons used by NYISO, MISO, and other transmission planning regions); SPP Market Monitor Initial Comments at 4-5 (noting SPP's existing transmission planning process); Western PIOs Initial Comments at 28-29 (noting Western Electricity Coordinating Council's planning scenarios and the integrated resource planning timelines of western vertically-integrated utilities).

[734] ACEG Reply Comments at 4-5; NextEra Initial Comments at 62-63.

[735] R Street Initial Comments at 6.

318. LADWP asserts that the proposed 20-year transmission planning horizon is likely the least disruptive horizon because of its current use by many transmission providers. LADWP further argues that a consistent transmission planning horizon will optimize asset investment and minimize public impacts; facilitate planning, coordination, and development of large-scale regional transmission projects; and ensure that transmission providers consider the same end point assessments of the evolving resource mix, environmental requirements that develop beyond a typical 10-year period, and significant maintenance and retirement issues.[736]

### ii. Requests for Flexibility

319. Several commenters recommend that the Commission provide transmission providers in each transmission planning region with the flexibility to propose other transmission planning horizons that may be appropriate and beneficial based on their planning processes.[737] APS states that it is not convinced that a prescriptive approach will yield the benefits that the Commission seeks.[738]

[736] LADWP Initial Comments at 2.

[737] Ameren Initial Comments at 13; APPA Initial Comments at 5; California Water Initial Comments at 14-15; EEI Initial Comments at 11; Indicated PJM TOs Initial Comments at 10; ISO-NE Initial Comments at 22-23; MISO TOs Initial Comments at 17; NARUC Initial Comments at 5-6; NESCOE Initial Comments at 25; New York State Department Initial Comments at 3; New York TOs Initial Comments at 10; Pennsylvania Commission Initial Comments at 5; TANC Initial Comments at 10; WIRES Initial Comments at 7; Xcel Initial Comments at 9.

[738] APS Initial Comments at 3.

320. NESCOE states that there is not one "right" transmission planning horizon and that it does not support a one-size-fits-all transmission planning horizon requirement.[739] NESCOE requests that the Commission allow transmission providers in each transmission planning region to demonstrate that existing tariff provisions are consistent with or superior to a final rule mandating a minimum transmission planning horizon, explaining—along with ISO-NE—that ISO-NE's Tariff does not provide a prescribed timeframe to request transmission analyses based on state-provided scenarios.[740] Relatedly, California Commission suggests that, instead of mandating a 20-year transmission planning horizon, the Commission should adopt NYISO's recommendation to provide transmission providers with the discretion, up to 20 years, to plan for their needs.[741]

321. PG&E understands that not every transmission need identified in the latter years of a 20-year transmission planning horizon will require immediate selection resolution, and it therefore asks the Commission to give individual transmission planning regions the flexibility to determine how to allow for monitoring and updating planning assumptions for transmission projects that meet transmission needs beyond 10 years.[742] ISO-NE

[739] NESCOE Initial Comments at 23-24.

[740] ISO-NE Initial Comments at 22-23; NESCOE Initial Comments at 24-25.

[741] California Commission Initial Comments at 11-12 (citing NYISO ANOPR Initial Comments at 37).

[742] PG&E Initial Comments at 4-6.

argues that the Commission should permit an approach that allows (but does not require) a transmission planning horizon beyond 10 years because the 20-year transmission planning horizon could potentially limit the identification of system issues during interim years, inhibit adaptation to evolving policies, and preclude the transmission planning process from considering public policies that may include shorter timeframes, which may limit the ability to adapt to emerging needs or changing laws.[743] NESCOE contends that a rigid 20-year transmission planning horizon may be counterproductive and could divert resources focused on meeting requests under ISO-NE's longer-term transmission planning process to study a time horizon that states, stakeholders, and ISO-NE may not find useful.[744]

322. OMS argues that the final rule should permit flexibility in transmission planning horizons and enable transmission planning regions to meet objectives through routine scenario-based planning within an appropriate study window.[745] Industrial Customers assert that transmission planning horizons should consider the time to identify, plan, and obtain siting and permitting approval to construct regional transmission facilities, and that timing can vary dramatically by region. Industrial Customers believe a stringent 20-year transmission planning horizon could create more uncertainty, resulting in stranded

[743] ISO-NE Initial Comments at 22-23.

[744] NESCOE Initial Comments at 24-25.

[745] OMS Initial Comments at 4-5.

transmission investments and increased transmission rates because it is difficult, if not impossible, to forecast transmission needs and requirements 20 years into the future.[746]

323. PJM States recommend, and Clean Energy Associations agree, that instead of requiring a transmission planning horizon of a particular length, the Commission should require each transmission provider to demonstrate that the transmission planning horizon it chooses is adequate to achieve the goals of Long-Term Regional Transmission Planning.[747]

324. New York State Department recommends that the final rule allow states to determine the appropriate transmission planning horizon since New York Public Service Commission has already issued orders directing long-term transmission and distribution planning with undefined terms.[748] EEI and US Chamber of Commerce explain that state regulators may not appreciate a rigid 20-year transmission planning horizon requirement given that some state resource procurement processes use a 10-year outlook, and the proposed transmission planning process may thus make resource decisions that are not state-sanctioned.[749] Consistent with their Coordinated Grid Planning Process, New York Commission and NYSERDA assert that the Commission should allow state regulators to

[746] Industrial Customers Reply Comments at 4-5.

[747] Clean Energy Associations Reply Comments at 5-6; PJM States Initial Comments at 4.

[748] New York State Department Initial Comments at 3.

[749] EEI Initial Comments at 11; US Chamber of Commerce Initial Comments at 6.

help determine the appropriate transmission planning horizon, especially in a single-state RTO/ISO such as NYISO.[750]

325. Louisiana Commission states that a 20-year transmission planning horizon may be longer than the planning horizon utilized in state integrated resource planning, explaining that its integrated resource planning rules allow for a 20-year default planning period, but also for alternative periods, and more importantly, require 5-year action plans.[751]

326. APPA argues, and TANC concurs, that the Commission should allow transmission planning regions to incorporate cost and benefit-tracking mechanisms to reduce the risk of speculative transmission projects.[752]

#### iii. Requests for a Different Transmission Planning Horizon

327. Several commenters argue that a 20-year transmission planning horizon is too long.[753] Indicated PJM TOs contend that the Commission should ensure that transmission planning horizons result in the identification of transmission facilities that

[750] New York Commission and NYSERDA Initial Comments at 10-12.

[751] Louisiana Commission Reply Comments at 8 (citing Corrected General Order Docket No R-30021 (LPSC 3/12/2012)).

[752] APPA Initial Comments at 26, 36; TANC Initial Comments at 10.

[753] Exelon Initial Comments at 4, 7-8; Indicated PJM TOs Initial Comments at 10; Industrial Customers Initial Comments at 18; Louisiana Commission Reply Comments at 13; Mississippi Commission Initial Comments at 12; Nebraska Commission Initial Comments at 3-4; NRECA Initial Comments at 27-28; NRG Initial Comments at 6-9, 14; Ohio Consumers Initial Comments at 20; Omaha Public Power Initial Comments at 3-4; PJM Initial Comments at 5, 58-62; US Chamber of Commerce Initial Comments at 5-6; Utah Commission Initial Comments at 13.

can be realistically planned and developed, and that 20 years may be too long given rapidly changing technology, generation mix, and demand patterns.[754] Mississippi Commission also favors a shorter transmission planning horizon, arguing that there is too much uncertainty to plan 20 to 40 years into the future.[755] NRECA argues that a 20-year transmission planning horizon may allow more alternatives to be considered, but cost efficacy is not guaranteed. Further, NRECA argues that planning beyond 10 years will by necessity devolve into a top-down process that would, at best, relegate actual load-serving entity resource plans and demand forecasts to a secondary status or, at worst, ignore them altogether, violating FPA section 217(b)(4).[756]

328. PJM Market Monitor states that uncertainty increases significantly as the transmission planning horizon is extended, and the transmission planning process should be both long-term and flexible, allowing transmission planners to change plans as reality changes.[757] Similarly, US Chamber of Commerce asserts that, as the length of the transmission planning horizon increases, the number of assumptions increases and the quality of assumptions decreases, rendering costs and benefits less certain. US Chamber of Commerce states that today's transmission grid was not forecasted at the turn of the

[754] Indicated PJM TOs Initial Comments at 10.

[755] Mississippi Commission Initial Comments at 12; *see also* Louisiana Commission Reply Comments at 13 (citing Mississippi Commission Initial Comments at 12).

[756] NRECA Initial Comments at 27-28.

[757] PJM Market Monitor Initial Comments at 3.

century, and, thus, forecasts made today for a similar period are likely to under or over-shoot transmission needs due to new and advancing generation technologies with commercial operation timeframes not yet known.[758] Nebraska Commission states that a 20-year transmission planning horizon may reduce the transmission planning process to an academic exercise due to the amount of speculation necessarily involved.[759]

329. Industrial Customers state that the Commission has not ruled against transmission planning horizons under 15 years and has acknowledged that the average time needed to develop and build a transmission project is 10 years.[760] Industrial Customers assert that, contrary to the Commission's view, most transmission planners use 10-year transmission planning horizons, and transmission investment should be driven by shorter timeframes to plan for economic and reliability needs.[761] Ohio Consumers note that the 5-year timeframe used by PJM's DFAX method is characterized by high uncertainty, so a longer timeframe would exacerbate inaccuracies.[762]

330. Several commenters argue that a 10-year transmission planning horizon could reduce speculation, such as with respect to the changing resource mix.[763] NRG states that

[758] US Chamber of Commerce Initial Comments at 6.

[759] Nebraska Commission Initial Comments at 3.

[760] Industrial Customers Initial Comments at 18.

[761] Industrial Customers Initial Comments at 16-19 (referencing NYISO and the Eastern Interconnection Planning Collaborative planning processes).

[762] Ohio Consumers Initial Comments at 20.

[763] Nebraska Commission Initial Comments at 3-4; NRG Initial Comments at 6-9,

a shorter, 10-year transmission planning horizon would fit within the time horizon necessary to make transmission investment decisions and still reflect regional policy goals.[764] Utah Commission notes that NorthernGrid's members in 2020 adopted a 10-year transmission planning horizon and objects to being compelled to abandon that planning horizon in favor of a one-size-fits-all mandate.[765]

331. PJM and Exelon advocate for a 15-year transmission planning horizon to reduce uncertainty and enhance reliability.[766] Exelon argues that a 15-year transmission planning horizon may yield less uncertain forecasts that are more likely to be actionable and better align with target dates in public policies.[767] PJM argues that its current 15-year transmission planning horizon is sufficient to plan and develop needed transmission, and that forecasts of fuel prices, load trends, generation retirement, and other relevant parameters become more uncertain the further one looks out. Moreover, PJM asserts, a longer transmission planning horizon leads to a greater probability that a transmission provider will commit to a transmission project that will look unfortunate in hindsight.[768]

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14; Omaha Public Power Initial Comments at 3-4.

[764] NRG Initial Comments at 6-9, 14.

[765] Utah Commission Initial Comments at 13.

[766] Exelon Initial Comments at 4, 7-8; PJM Initial Comments at 5, 58-62.

[767] Exelon Initial Comments at 4, 7-8.

[768] PJM Initial Comments at 59-62 (citing *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Notice of Technical Conference, Docket No. AD05-3-000, at 1 (issued Feb. 16, 2005)).

332. Some commenters argue that a transmission planning horizon longer than 20 years may be warranted to capture the longer-term benefits of transmission facilities.[769] ACEG recommends that the Commission consider up to a 40-year transmission planning horizon to match the expected life of most transmission assets.[770] CARE Coalition argues that a 40-year transmission planning horizon would be consistent with standard practice in economics and public policy of evaluating benefits over the life of the asset, and that the long lead time to develop transmission facilities justifies a longer planning horizon.[771]

#### iv. Opposition to Requests for a Different Transmission Planning Horizon

333. Several commenters dispute claims that a 20-year transmission planning horizon introduces risks from uncertainty and that a shorter planning horizon is more appropriate.[772] Southeast PIOs claim that the risk of unaddressed transmission needs grows over time because of long lead times needed for transmission development, and that SERTP's 10-year transmission planning horizon prevented Georgia Power from

[769] ACEG Initial Comments at 6-7, 24; CARE Coalition Initial Comments at 40-41; Interwest Initial Comments at 5; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 19-20; PIOs Initial Comments at 15; SEIA Initial Comments at 6.

[770] ACEG Initial Comments at 6, 24.

[771] CARE Coalition Initial Comments at 40-41.

[772] ACORE Reply Comments at 5 (citing EPSA Initial Comments at 7; ITC Initial Comments at 9; Mississippi Commission Initial Comments at 12; PJM Initial Comments at 58-62); Concerned Scientists Reply Comments at 18-19; PJM Initial Comments at 58-62; Southeast PIOs Reply Comments at 23-25 (citing Dominion Initial Comments at 19; Southern Initial Comments at 19, 32-33).

using that process to plan for its long-term North Georgia Reliability & Resilience Plan and its goal to integrate 6,000 MW of renewable resources by 2035.[773] Southeast PIOs assert that a longer transmission planning horizon will put future transmission needs on the radar for transmission planners and, if updated frequently, allow transmission providers to select transmission facilities conditional on subsequent transmission planning cycles, which affords planners flexibility to determine the need for the facility and whether there are more cost-effective alternatives.[774] ACORE notes that the NOPR addresses the uncertainty about the future by requiring the use of multiple Long-Term Scenarios that are revised every three years.[775]

334. Several commenters state that the transmission planning horizon should not extend beyond 20 years to avoid overly speculative long-term forecasts.[776] Entergy asserts that looking beyond 20 years would increase the likelihood of errors, risk billions of dollars in investments that may prove to be misguided, and amplify the risk of planning a transmission system that poorly aligns with actual future needs.[777] Illinois Commission

[773] Southeast PIOs Reply Comments at 24 (citing Southeast PIOs Initial Comments at 27-28).

[774] *Id*. at 23-25.

[775] ACORE Reply Comments at 5.

[776] Arizona Commission Initial Comments at 3-4; California Commission Initial Comments at 11-13; Entergy Initial Comments at 9-11; Georgia Commission Initial Comments at 2-3; Pennsylvania Commission Initial Comments at 5; US Chamber of Commerce Initial Comments at 4, 6.

[777] Entergy Initial Comments at 9-11.

states that a transmission planning horizon longer than 20 years would make it difficult to accurately predict the factors relevant to transmission planning.[778] Clean Energy Buyers propose that transmission providers seeking to adopt a transmission planning horizon beyond 20 years should be required to demonstrate the justness and reasonableness of that transmission planning horizon.[779]

335. Certain TDUs and Louisiana Commission oppose a 40-year transmission planning horizon.[780] Certain TDUs emphasize that, as evidenced by the Michigan Thumb Loop transmission project, assumptions such as the resource mix can change in as few as seven years.[781] Louisiana Commission argues that longer periods, such as the 40-year transmission planning horizon proposed by some commenters, will greatly increase the risk for errors and wasted investments. According to Louisiana Commission, transmission planning horizons should neither exceed the availability of reasonable data and assumptions nor create unnecessary risks that ratepayers will be required to fund transmission facilities that do not deliver expected benefits.[782]

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[778] Illinois Commission Initial Comments at 6.

[779] Clean Energy Buyers Initial Comments at 12-13.

[780] Certain TDUs Reply Comments at 3-6 (citing ACEG Initial Comments at 24); Louisiana Commission Reply Comments at 8.

[781] Certain TDUs Reply Comments at 3-6.

[782] Louisiana Commission Reply Comments at 8.

### v. Meaning and Scope of Transmission Planning Horizon

336. Several commenters request that the Commission define the 20-year transmission planning horizon as a simple 20-year period, and not a 20-year period starting from the estimated in-service date of the transmission facilities, which would result in forecasting transmission needs beyond 20 years.[783] Kentucky Commission Chair Chandler states that the usefulness of Long-Term Regional Transmission Planning and measuring benefits 20 years after a transmission project's in-service date will decrease if each project's relative benefits cannot be adequately measured and identified.[784] PPL argues that tying the transmission planning horizon to the study date rather than the solution in-service date will facilitate a more realistic, certain, and simple transmission planning process and reduce the need for additional analysis.[785] US Chamber of Commerce adds that beginning at the in-service date of the transmission facilities would extend the effective transmission planning horizon to 25-30 years, thereby further increasing the uncertainty of Long-Term Regional Transmission Planning; thus, US Chamber of Commerce argues the Commission should use the 20-year transmission planning horizon as a ceiling, rather than a floor, consistent with the far end of most state planning horizons, which would

[783] Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12-13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

[784] Kentucky Commission Chair Chandler Reply Comments at 2.

[785] PPL Initial Comments at 6.

protect transmission planners from being forced to plan beyond the requirements of applicable state law.[786]

337. Policy Integrity requests that the Commission clarify the details of the 20-year time horizon, stating that it is unclear whether the Commission intended the 20-year time horizon for Long-Term Regional Transmission Planning to be tied to construction commencing in year 20.[787] ISO-NE and Policy Integrity seek clarification that, if the Commission requires that transmission providers must study what is needed over the next 20 years, transmission providers are not precluded from evaluating what needs to be built in the short and medium terms.[788] Industrial Customers assert that the proposed 20-year transmission planning horizon is unclear because some commenters interpret the Commission's proposal as requiring a 20-year transmission planning horizon for Long-Term Regional Transmission Planning,[789] while others argue it requires a 20-year transmission planning horizon in existing regional transmission planning processes.[790]

338. Several commenters support a 20-year transmission planning horizon if Long-Term Scenarios are used to inform the development of transmission facilities but not used

[786] US Chamber of Commerce Initial Comments at 6.

[787] Policy Integrity Initial Comments at 5.

[788] ISO-NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

[789] Industrial Customers Reply Comments at 5-6 (citing NARUC Initial Comments at 5).

[790] Industrial Customers Reply Comments at 5-6 (citing California Commission Initial Comments at 11).

to select transmission facilities or to dictate construction.[791] TANC does not believe that a 20-year transmission planning horizon should be used for local transmission planning processes or selection.[792] Nebraska Commission states that using a 20-year transmission planning horizon for only research, study, and projections will avoid speculation, increased costs, and unjust and unreasonable rates.[793] NRECA asserts that using a 20-year transmission planning horizon in Long-Term Regional Transmission Planning to select transmission projects will not produce the granularity and certainty needed to assign costs to beneficiaries.[794] Similarly, Ohio Consumers argue that too little is known about the location of future loads and resources and the direction of power flows over 20 years to use a 20-year transmission planning horizon for cost allocation purposes.[795] NRG argues that use of a 20-year transmission planning horizon to allocate costs will lead to unjust and unreasonable outcomes, and instead, a 10-year transmission planning horizon is appropriate.[796] New England Systems state that the Commission should adjust

[791] NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6-9, 14; Ohio Consumers Initial Comments at 20; *see also* Dominion Reply Comments at 4-5 (citing NARUC Initial Comments at 5); PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

[792] TANC Initial Comments at 10.

[793] Nebraska Commission Initial Comments at 3.

[794] NRECA Initial Comments at 23-24 (citing GDS Assocs., Inc., Report, at 10 (Aug. 17, 2022)).

[795] Ohio Consumers Initial Comments at 1, 20.

[796] NRG Initial Comments at 6-9, 14.

the NOPR's focus on transmission planning horizons toward an evolutionary and evidence-based transmission planning process aimed at mitigating avoidable costs for operating generation out of economic merit order and at improving the utilization of renewable resources that experience curtailment due to congestion.[797]

339. Some commenters support a 20-year transmission planning horizon only if the latter portion of the planning horizon is not used to direct the development of transmission facilities.[798] SERTP Sponsors state that the Commission should not require that regional transmission expansion be based on transmission planning horizons that are incompatible with the planning horizons used for integrated resource planning or supply-side resource plan development, or that involve a degree of speculation that the states comprising a transmission planning region are not willing to accept.[799] SPP Market Monitor contends that if the Commission requires all RTOs/ISOs to perform a 20-year study, the final rule should also provide guidance on how information determined in that long-term study will be used. SPP Market Monitor supports a secondary, shorter-term

[797] New England Systems Initial Comments at 21-22.

[798] APS Initial Comments at 3-4; Kansas Commission Initial Comments at 13-14; Maryland Energy Administration Initial Comments at 3; SERTP Sponsors Initial Comments at 20; Shell Initial Comments at 21; SPP Market Monitor Initial Comments at 5-6.

[799] SERTP Sponsors Initial Comments at 20.

transmission planning horizon of 10 years that could be based on the results of the longer-term 20-year studies.[800]

340. Shell suggests that the 20-year transmission planning horizon include a developmental "Actionable Period" for the first 10 years, during which developers may be willing to invest in generation projects, or the RTOs/ISOs or utilities may be willing to commit to and authorize the construction of new transmission. Shell proposes that there would be an "Indicative Period" for the following 10 years, which would be used to drive the Actionable Period so that the Commission establishes a process that converges and integrates short, medium, and long-term planning. Shell asserts that its proposal could foster more comprehensive and efficient Long-Term Regional Transmission Planning and inform existing regional transmission planning processes.[801] To remove speculative assumptions from Long-Term Regional Transmission Planning, Arizona Commission similarly suggests that the Commission divide the 20-year transmission planning horizon into two equal parts: a "more certain" forecast and a "flexible" forecast.[802] Likewise, APS recommends that the Commission adopt a 20-year transmission planning horizon for "potential projects" and a 10-year planning horizon for "planned projects" to provide greater regional flexibility.[803]

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[800] SPP Market Monitor Initial Comments at 5-6.

[801] Shell Initial Comments at 19-23.

[802] Arizona Commission Initial Comments at 3-4.

[803] APS Initial Comments at 3-4.

341. Kansas Commission, Mississippi Commission, and NRECA state that the results of Long-Term Regional Transmission Planning should be considered informational only.[804] Kansas Commission requests that the Commission establish solid evidentiary and policy bases to support a 20-year transmission planning horizon before imposing such a requirement.[805] Mississippi Commission believes that transmission construction decisions should use a 10-year transmission planning horizon.[806]

342. Some commenters rebut arguments that Long-Term Regional Transmission Planning should be performed for informational purposes only.[807] ACEG contends that adopting the proposed transmission planning methods is essential to accomplishing the Commission's responsibilities and that less stringent requirements have not led to much-needed development of high-capacity transmission throughout the country. ACEG further states that providing informational reports will do little to remedy undue discrimination and achieve actual transmission plans.[808] DC and MD Offices of People's Counsel state that the potential benefits to ratepayers and other stakeholders of a 20-year transmission planning horizon is significantly diminished if transmission planning is

[804] Kansas Commission Initial Comments at 13-14; Mississippi Commission Reply Comments at 6; NRECA Initial Comments at 23.

[805] Kansas Commission Initial Comments at 13.

[806] Mississippi Commission Reply Comments at 6.

[807] ACEG Reply Comments at 10; DC and MD Offices of People's Counsel Reply Comments at 5; SEIA Reply Comments at 2.

[808] ACEG Reply Comments at 10.

simply an academic exercise, without actual impact on future transmission development.[809] SEIA argues that the Commission should mandate that scenarios developed under the final rule be used in transmission planning rather than for informational purposes only or contingent on the approval of state regulators.[810]

343. Business Council for Sustainable Energy states that transmission planning should consider the length of time that it takes for transmission assets to be built and the estimated useful life of those facilities.[811] California Municipal Utilities argue, and TANC concurs, that any lengthening of the transmission planning horizon must be accompanied by consumer protections that guard against speculative siting of generation and a rigorous re-evaluation of planning assumptions and other relevant factors, such as commercial viability of transmission projects and the associated resources.[812]

### c. Commission Determination

344. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. We further clarify that using a transmission planning horizon of no less than 20

[809] DC and MD Offices of People's Counsel Reply Comments at 5.

[810] SEIA Reply Comments at 2.

[811] Business Council for Sustainable Energy Initial Comments at 4.

[812] California Municipal Utilities Initial Comments at 3; TANC Initial Comments at 10.

years means that transmission providers must develop Long-Term Scenarios to identify Long-Term Transmission Needs that will materialize in the 20 years or more following the commencement of the Long-Term Regional Transmission Planning cycle.

345. In requiring a transmission planning horizon of not less than 20 years, we strike a balance. On the one hand, a 20-year transmission planning horizon extends far enough into the future that transmission providers can proactively identify Long-Term Transmission Needs that could be met with more efficient or cost-effective Long-Term Regional Transmission Facilities; in contrast, as discussed below, a transmission planning horizon less than 20 years may limit transmission providers' ability to adequately plan for Long-Term Transmission Needs. Specifically, as described in the NOPR, a 20-year transmission planning horizon allows for more time between when a transmission facility is identified to meet a future transmission need, and when the transmission need materializes, allowing for sufficient time to identify, plan, obtain siting and permitting approval for, and construct Long-Term Regional Transmission Facilities. Moreover, as some commenters observe, several transmission providers, including MISO, SPP, and NYISO, already use a 20-year transmission planning horizon. On the other hand, based on the record before us, we find that there may be sufficient uncertainty with regard to system conditions and transmission needs beyond a 20-year horizon such that it may be challenging for transmission providers to forecast Long-Term Transmission Needs across that time period, especially for those transmission providers that do not presently conduct, and thus do not have experience with, long-term regional transmission planning. Accordingly, we decline to adopt a requirement to use a transmission planning horizon

that exceeds 20 years. However, this does not preclude transmission providers from proposing to use a transmission planning horizon of more than 20 years.

346. We clarify that transmission providers must plan for the entire duration of the 20-year transmission planning horizon. Specifically, transmission providers must, among other requirements established in this final rule, develop and use Long-Term Scenarios to identify Long-Term Transmission Needs occurring in any period of the 20-year transmission planning horizon and to evaluate potential transmission solutions to those needs.

347. Certain commenters either misstate aspects of the proposed 20-year transmission planning horizon or request clarification regarding the horizon.[813] We specify that the transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date. The transmission planning horizon is not tied to the in-service date of any identified transmission solution; rather, potential transmission solutions are identified after identifying Long-Term Transmission Needs that manifest during the 20-year transmission planning horizon.

348. We disagree with commenters that assert that a 20-year transmission planning horizon could result in Long-Term Regional Transmission Planning based on speculative transmission needs[814] or, relatedly, that a 20-year transmission planning horizon is only

[813] Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12-13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

[814] *E.g.*, TANC Initial Comments at 10.

appropriate if Long-Term Scenarios are not used to select Long-Term Regional Transmission Facilities.[815] We find these assertions to be unfounded. In fact, the Long-Term Regional Transmission Planning requirements adopted in this final rule are designed to avoid over-building transmission in response to speculative transmission needs through a series of tools and safeguards, discussed at length above.[816] To highlight just one of these safeguards, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final rule, we require transmission providers to reevaluate certain previously selected Long-Term Regional Transmission Facilities in some circumstances to confirm that the Long-Term Regional Transmission Facility continues to meet the transmission providers' selection criteria. This reevaluation process will help ensure that the continued selection of Long-Term Regional Transmission Facilities is based on the use of updated information regarding the existence of a Long-Term Transmission Need and the benefits that transmission providers expect a Long-Term Regional Transmission Facility to provide.

349. We disagree with commenters that assert that the Commission should adopt a shorter transmission planning horizon.[817] A transmission planning horizon of less than

[815] NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6-9, 14; Ohio Consumers Initial Comments at 20; *see also* PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

[816] *See supra* Participation in Long-Term Regional Transmission Planning section.

[817] Exelon Initial Comments at 4, 7-8; Industrial Customers Initial Comments at 18; Mississippi Commission Initial Comments at 34; Nebraska Commission Initial Comments at 3-4; NRECA Initial Comments at 27-28; NRG Initial Comments at 6-9, 14;

20 years would fail to sufficiently capture Long-Term Transmission Needs given that at least some of the drivers of such needs extend up to 20 years into the future (e.g., many state laws include requirements to be met 15 to 20 years in the future). Additionally, a shorter minimum transmission planning horizon may not allow for sufficient time to develop Long-Term Regional Transmission Facilities with long lead-time requirements or to compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.

350. We disagree with commenters that assert requiring a 20-year transmission planning horizon is incompatible with planning horizons used with state integrated resource planning.[818] In addition to the discussions in the Overall Need for Reform and Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning sections regarding state integrated resource planning, we note that regardless of the planning horizon used in a state integrated resource planning process, the results of that process can be incorporated into Long-Term Regional Transmission Planning to identify Long-Term Transmission Needs. In fact, as explained in State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three) section below, integrated resource plans are part of the Categories of Factors and thus, transmission providers must incorporate information on

Omaha Public Power Initial Comments at 3-4; PJM Initial Comments at 5, 58-62; US Chamber of Commerce Initial Comments at 6; Utah Commission Initial Comments at 13.

[818] SERTP Sponsors Initial Comments at 21.

the load-serving entities' projected loads and resources over the planning horizon. The fact that a state integrated resource plan does not extend out a full 20 years—or extends further into the future—does not change the obligation for transmission providers to incorporate the information that is available over the 20-year transmission planning horizon.

351. In response to ISO-NE, and Policy Integrity,[819] the 20-year transmission planning horizon is distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from the estimated in-service date, as discussed in the Required Benefits section.

### 2. Frequency of Long-Term Scenario Revisions

#### a. NOPR Proposal

352. In the NOPR, the Commission proposed to require each transmission provider to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in the previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors. The Commission also proposed to require that the development of Long-Term Scenarios be completed within three years, before the next three-year assessment commences.[820]

[819] ISO-NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

[820] NOPR, 179 FERC ¶ 61,028 at P 97.

353. The Commission preliminarily found that a three-year frequency requirement balances the need of transmission providers to reassess changes in the resource mix and demand, as technology, markets, and policies have the potential to rapidly change, against the burden of developing Long-Term Scenarios that can take a year or longer to produce. The Commission stated that this three-year frequency requirement would allow transmission providers to identify new transmission needs driven by changes in the resource mix and demand during the interim years of the transmission planning period, and update previously identified transmission needs, if warranted.[821]

**b. Comments**

**i. Support for Frequency of Long-Term Scenario Revisions**

354. Many commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.[822] Arizona

[821] NOPR, 179 FERC ¶ 61,208 at P 99.

[822] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8-9; AEP Initial Comments at 5, 8, 13-14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6-8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore

Commission and Interwest state that the proposed three-year process aligns with their existing regional transmission planning processes.[823] Several commenters assert that this proposal allows for Long-Term Scenarios to remain accurate and account for material technological, political, environmental, and operational developments in the energy industry,[824] with some commenters indicating that past experience demonstrates that the energy industry is rapidly changing.[825] For example, PIOs share that MISO recently recognized assumptions in its MISO Transmission Expansion Plan did not capture the rate of change for the region's fuel mix.[826]

355. Pennsylvania Commission states that routine reviews could update information and data, justify modifications to transmission plans, and reduce the risk of uneconomic

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Wind Initial Comments at 2; New Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13-14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5-6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

[823] Arizona Commission Initial Comments at 3; Interwest Initial Comments at 6-8.

[824] Advanced Energy Buyers Initial Comments at 7; California Water Initial Comments at 15; ELCON Initial Comments at 11; Joint Consumer Advocates at 8; PIOs Initial Comments at 17; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11.

[825] Advanced Energy Buyers Initial Comments at 7; ELCON Initial Comments at 11.

[826] PIOs Initial Comments at 16-17 (stating that MISO's prediction for changes in its fuel mix 15 years out in the MISO Transmission Expansion Plan 2020 Report had already materialized before that final report was published).

transmission investments.[827] ELCON notes that the proposed three-year reassessment provides the opportunity to consult recent data and update the probability of each scenario, which will produce better outcomes in the transmission planning process.[828] Joint Consumer Advocates state that long-term transmission plans must be revisited regularly and with sufficient frequency to ensure that they remain accurate and account for material developments.[829] AEE states that triennial updates will provide a suitable amount of time for stakeholders to complete comprehensive studies while also ensuring that scenarios do not become stale as advanced energy technology deployment scales more rapidly and policy changes disrupt existing assumptions.[830]

356. Louisiana Commission avers that the proposed three-year reassessment will prevent transmission providers from ignoring changes that might better reflect future assumptions.[831] PIOs state that a three-year update will also help address issues that could occur if a transmission provider is too aggressive or conservative when defining

[827] Pennsylvania Commission Initial Comments at 5.

[828] ELCON Initial Comments at 11.

[829] Joint Consumer Advocates Initial Comments at 8.

[830] AEE Initial Comments at 8-9.

[831] Louisiana Commission Reply Comments at 9.

scenarios.[832] DC and MD Offices of People's Counsel recommend that plans be updated every three years.[833]

357. Entergy and Interwest state that a three-year reassessment cycle balances the need for recent data and the time and resources needed to develop the updates.[834] LADWP states that a rolling near-term planning horizon provides the long-term transmission planning process with up-to-date information without being too frequent.[835] New Jersey Commission notes that reassessments more frequent than every three years would be overly burdensome.[836] Similarly, Nebraska Commission states that a frequency shorter than every three years would require almost constant updates from transmission providers, which would drive up costs, while a frequency longer than three to five years could risk the underlying information becoming stale between revisions.[837]

358. Certain TDUs suggest that the Commission address concerns that a three-year review period would put significant strain on transmission provider resources by clarifying that three-year assessments would review the key drivers and assumptions behind a transmission plan with updates as needed for material changes rather than a

[832] PIOs Initial Comments at 17.

[833] DC and MD Offices of People's Counsel Reply Comments at 2.

[834] Entergy Initial Comments at 11; Interwest Initial Comments at 6.

[835] LADWP Initial Comments at 3.

[836] New Jersey Commission Initial Comments at 11.

[837] Nebraska Commission Initial Comments at 4.

rerun of the full transmission planning process. In addition, Certain TDUs state that a three-year reassessment of initial transmission plans would result in more transparency and consideration of alternatives in the transmission planning process.[838] In contrast, PJM requests that the Commission clarify that Long-Term Scenarios would be completely updated with new data, updated factors, and the best information available at least every three years, not merely partially reassessed. PJM also requests that the Commission clarify that scenario evaluations will not overlap, as re-runs are expensive, and a predictable three-year clock will make the process run smoothly.[839]

359. AEP requests that the Commission require all transmission planning regions to continuously follow the same, consistent three-year transmission planning cycles to align future efforts and ease burdens on transmission providers and developers operating in multiple transmission planning regions and to promote better coordination among regions concerning potential interregional transmission solutions.[840]

360. Southeast PIOs support the NOPR proposal to require transmission providers to reassess and revise Long-Term Scenarios every three years, arguing that it would synchronize with existing state processes and ensure that long-term regional transmission plans remain an up-to-date resource for state planning.[841] Similarly, Certain TDUs argue

[838] Certain TDUs Reply Comments at 7.

[839] PJM Initial Comments at 6, 63-64.

[840] AEP Initial Comments at 5, 8, 13-14; AEP Reply Comments at 5.

[841] Southeast PIOs Reply Comments at 25.

that a five-year transmission planning cycle is too long and that a three-year transmission planning cycle would be more likely to account for unforeseen changes, helping to prevent inefficient transmission development and balance planning for future needs with the need to quickly identify material changes to planning assumptions.[842]

### ii. Concerns about Frequency of Long-Term Scenario Revisions

361. Some commenters urge the Commission to provide flexibility for transmission providers to determine the frequency at which they must develop Long-Term Scenarios by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.[843] EEI requests that the Commission allow transmission providers in each transmission planning region to initiate a new Long-Term Scenario process in lieu of a refresh of old Long-Term Scenarios.[844] California Commission and Omaha Public Power argue that requiring transmission providers to reassess and revise Long-Term Scenarios at least every three years will

[842] Certain TDUs Reply Comments at 5-6.

[843] Ameren Initial Comments at 12-13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO-NE Initial Comments at 24; MISO Initial Comments at 28-29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6-7; NESCOE Initial Comments at 25-26; OMS Initial Comments at 4-5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

[844] EEI Initial Comments at 12.

create a significant compliance burden without improving planning outcomes, such as forecast accuracy.[845]

362. MISO TOs argue that flexibility is warranted because MISO is already implementing Long-Term Regional Transmission Planning, as well as reassessing its data as needed.[846] MISO states that the NOPR proposal is overly prescriptive, may not reflect stakeholder and regional needs, and could result in a compliance exercise without the prospect of transmission expansion.[847] NESCOE and OMS suggest that the Commission require transmission providers to reassess Long-Term Scenarios at regular intervals but leave the timing of that reassessment to the transmission planning region.[848] MISO also recommends that the Commission allow transmission providers to reuse Long-Term Scenarios as long as they update the relevant input data to reflect the latest available information.[849]

363. Duke asserts that the Commission should allow transmission planning regions to propose their own cycles to reassess and revise Long-Term Scenarios to meet the needs of the region, keep pace with markets and policies across the country, and align their

[845] California Commission Initial Comments at 16; Omaha Public Power Initial Comments at 3.

[846] MISO TOs Initial Comments at 17.

[847] MISO Initial Comments at 28.

[848] NESCOE Initial Comments at 25-26; OMS Initial Comments at 4-5.

[849] MISO Initial Comments at 29.

processes with state integrated resource planning processes.[850] Similarly, WIRES requests a variance to the proposed three-year scenario reassessment requirement because three years may be too short and could potentially be disruptive or increase costs. WIRES further asks that the Commission clarify that transmission providers are not required to reassess previously approved transmission projects as part of their triennial review process.[851]

364. Pacific Northwest State Agencies state that the Commission should set three years as a minimum and provide transmission planning regions with the flexibility to work with states to determine the appropriate schedule for developing Long-Term Scenarios.[852] Similarly, Vermont State Entities and Pennsylvania Commission argue that transmission planning regions should have the flexibility to conduct reassessments at intervals shorter than every three years.[853]

365. NYISO recommends that the final rule should allow transmission planning regions to modify or add to their Long-Term Scenarios to account for changes that would significantly affect their analysis when they occur instead of waiting for the next transmission planning cycle. NYISO further requests that the Commission clarify that, if

[850] Duke Initial Comments at 12.

[851] WIRES Initial Comments at 7.

[852] Pacific Northwest State Agencies Initial Comments at 15.

[853] Pennsylvania Commission Initial Comments at 5; Vermont State Entities Initial Comments at 5.

a transmission planning region requires more than three years to complete a given transmission planning cycle, it may extend the three-year time period. In addition, NYISO requests that the Commission permit transmission providers in each transmission planning region to commence the next Long-Term Regional Transmission Planning cycle using current information even if the prior transmission planning cycle is running in parallel. NYISO adds that the Commission should allow transmission planning regions to use their existing Long-Term Scenarios for the duration of a Long-Term Regional Transmission Planning cycle, even if it runs beyond three years, to avoid stopping and re-starting that cycle due to changes in circumstances.[854]

366. Some commenters raise concerns that the proposal to require development of Long-Term Scenarios at least every three years may create overlapping planning assessments and suggest ways to avoid that situation.[855] ISO-NE states that the timeframe for Long-Term Regional Transmission Planning should account for all the elements of the process, such as implementing the process for selecting transmission solutions, before the next long-term study begins. ISO-NE indicates that this will allow subsequent Long-Term Regional Transmission Planning studies to account for the

[854] NYISO Initial Comments at 19.

[855] Eversource Initial Comments at 15; ISO-NE Initial Comments at 24; NESCOE Initial Comments at 26; PJM Initial Comments at 63.

outcomes of the preceding transmission planning cycle and avoid unnecessary study overlap between cycles.[856]

367. Eversource suggests that the Commission require completion of project selection before the development of the next set of Long-Term Scenarios, arguing that it would undermine the project selection process if the current three-year Long-Term Scenario cycle fails to include selected transmission facilities from the prior three-year cycle.[857]

368. Similarly, NESCOE is concerned that the three-year Long-Term Scenario cycle requirement is inflexible and could interfere with existing procedures in New England. NESCOE states that ISO-NE's longer-term transmission planning process requires that a planning process be concluded before a new one can begin, and that a request for a longer-term transmission study may be submitted to ISO-NE no earlier than six months after the conclusion of the prior study.[858]

369. Some commenters argue that requiring transmission providers to reassess and revise their Long-Term Scenarios every three years may be too frequent and costly, asserting that between every three and five years may be more appropriate.[859] ITC avers that a three-year transmission planning cycle for Long-Term Regional Transmission

[856] ISO-NE Initial Comments at 24.

[857] Eversource Initial Comments at 15.

[858] NESCOE Initial Comments at 26.

[859] ACEG Initial Comments at 7, 25; Breakthrough Energy Initial Comments at 12-13; EEI Initial Comments at 12; Indicated PJM TOs Initial Comments at 11-12; ITC Initial Comments at 5, 9-11; Pine Gate Initial Comments at 19-20.

Planning would exceed the capabilities of the transmission providers administering the process.[860] Likewise, NRECA asserts that developing multiple Long-Term Scenarios and updating them every three years will require significant time and resources, as well as substantial changes in transmission planning throughout the country. NRECA asserts that existing power supply and transmission planning models employ different assumptions that cannot be used to prepare 20-year Long-Term Scenarios, much less update them every three years.[861]

### iii. Support for Different Frequency of Long-Term Scenario Revisions

370. Western PIOs support mandating a two-year timeframe for revision, as three years may be too long and therefore may miss important updated data inputs.[862]

371. Shell argues that the Commission should require transmission providers to reassess and revise their Long-Term Scenarios every five years, asserting that the proposal to use three years could create too much uncertainty and delay the development of renewable generation being developed to comply with state climate objectives and resource adequacy requirements in forward-looking capacity markets.[863] Indicated PJM TOs argue that three years may be insufficient to perform relevant studies and

[860] ITC Initial Comments at 10.

[861] NRECA Initial Comments at 23 (citing GDS Assocs., Report, at 8-10 (Aug. 17, 2022)).

[862] Western PIOs Initial Comments at 30.

[863] Shell Initial Comments at 18-19.

recommend that the Commission provide transmission providers with the flexibility to adopt four- or five-year transmission planning cycles.[864]

372. Exelon argues that a three-year transmission planning cycle is too short, as it is unlikely that transmission needs will surface within three years, and that conducting a study so soon could create uncertainty that recently selected transmission projects will be revisited. Exelon instead recommends that the final rule adopt a five-year transmission planning cycle requirement with a provision that requires transmission providers to initiate a new cycle sooner, with good reason, to better align with the time needed to permit and construct new transmission infrastructure.[865]

373. Similarly, PPL argues that a five-year transmission planning cycle will allow sufficient time for one transmission planning cycle to be completed before the subsequent cycle commences.[866] Pine Gate states that a five-year transmission planning cycle is warranted given the size and complexity of transmission planning regions and the time needed to receive and incorporate stakeholder feedback and to achieve consensus on cost allocation. Pine Gate further notes that a five-year transmission planning cycle would more closely align the results of Long-Term Regional Transmission Planning with the time horizons for reliability planning and other transmission planning processes.[867]

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[864] Indicated PJM TOs Initial Comments at 11-12.

[865] Exelon Initial Comments at 9.

[866] PPL Initial Comments at 6.

[867] Pine Gate Initial Comments at 20-21.

374. SPP argues in favor of the update procedures in its current transmission planning processes rather than the three-year schedule for updating Long-Term Scenarios proposed in the NOPR. SPP states that it performs a 20-year assessment that incorporates Long-Term Scenarios at least once every five years and that, on an annual basis, SPP assesses data inputs and factors incorporated into the assessment.[868]

### iv. Miscellaneous Comments

375. Several commenters state that the Commission should regularly review transmission planning processes and assumptions to account for new developments.[869] Pattern Energy states that the best way to make 20-year transmission plans useful is for their outputs to be fed into near-term (i.e., five-to-seven-year horizon) transmission planning activities.[870]

376. ELCON recommends that the Commission hold a technical conference after the first three-year reassessment period for Long-Term Scenarios to allow transmission providers to offer their experiences with and best practices for Long-Term Regional Transmission Planning.[871]

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[868] SPP Initial Comments at 5-6.

[869] Clean Energy Buyers Initial Comments at 13; SREA Reply Comments at 26-27.

[870] Pattern Energy Initial Comments at 22.

[871] ELCON Initial Comments at 11.

### c. Commission Determination

377. We modify the NOPR proposal to require transmission providers in each transmission planning region to reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years. In implementing this requirement, transmission providers in each transmission planning region must reassess whether the data inputs and factors incorporated in previously developed Long-Term Scenarios need to be updated and then revise those Long-Term Scenarios, as needed, to reflect updated data inputs and factors. At the outset of a Long-Term Regional Transmission Planning cycle, transmission providers may develop the new Long-Term Scenarios either by crafting entirely new Long-Term Scenarios, or by updating the data inputs and factors of previously developed Long-Term Scenarios.

378. To assist transmission providers in implementing the requirement to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, we clarify that the process, which begins with the development of Long-Term Scenarios using best available data inputs, and proceeds to identifying Long-Term Transmission Needs, measuring the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluating and deciding whether to select Long-Term Regional Transmission Facilities (collectively, the Long-Term Regional Transmission Planning cycle),[872] must conclude at a date that is no later than five years after the date that it began.

[872] The Long-Term Regional Transmission Planning cycle encompasses all components of Long-Term Regional Transmission Planning, including each of these

379. While we find that the record supports a five-year interval before new Long-Term Scenarios must be developed, we also conclude that transmission providers should not need the full five-year period to reach the point in Long-Term Regional Transmission Planning at which they decide whether to select Long-Term Regional Transmission Facilities that they have evaluated. Accordingly, we require transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle and determine whether to select Long-Term Regional Transmission Facilities no later than three years from the date when the Long-Term Regional Transmission Planning cycle began.[873] Specifically, we find the record demonstrates that three years provides sufficient time for transmission providers to develop Long-Term Scenarios, identify Long-Term Transmission Needs, measure the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluate and decide whether to select Long-Term Regional Transmission Facilities.[874] At the same time, we are persuaded by

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foundational steps.

[873] To be clear, nothing in this final rule prevents transmission providers from evaluating and selecting *additional* Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins. However, if Long-Term Regional Transmission Facilities are selected at year three of the Long-Term Regional Transmission Planning cycle, those same Long-Term Regional Transmission Facilities cannot be de-selected during the remainder of the current five-year planning cycle.

[874] *See* ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8-9; AEP Initial Comments at 5, 8, 13-14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations

commenters' concerns that requiring the Long-Term Regional Transmission Planning cycle to repeat at three-year intervals could be administratively burdensome, and that the benefit of updating Long-Term Scenarios every three years may not outweigh those additional burdens.[875] We therefore find that requiring selection decisions to occur within three years of commencing a Long-Term Regional Transmission Planning cycle, while allowing as long as five years between the commencement of each planning cycle, strikes an appropriate balance by ensuring timely identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities, while balancing the administrative burden associated with updating the Long-Term Scenarios

Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6-8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13-14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5-6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

[875] *See* Ameren Initial Comments at 12-13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO-NE Initial Comments at 24; MISO Initial Comments at 28-29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6-7; NESCOE Initial Comments at 25-26; OMS Initial Comments at 4-5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

that form the basis for Long-Term Regional Transmission Planning during each planning cycle.[876]

380. We find that requiring transmission providers to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years is necessary to ensure that the Long-Term Scenarios accurately reflect factors that may change over the five-year time span, such as changes in technology, load forecasts, or federal, federally-recognized Tribal, state, or local laws. Furthermore, regular scenario reassessment and revision may also address some of the uncertainty associated with Long-Term Regional Transmission Planning over a 20-year transmission planning horizon that some commenters assert may result in under-building or over-building transmission facilities.[877] As discussed below in the Specificity of Data Inputs section, nothing in this final rule prohibits transmission providers from updating the inputs used to inform Long-Term Scenarios during a Long-Term Regional Transmission Planning cycle.

381. As discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final rule, transmission providers must designate a point in the evaluation process at which they will make a decision to either select or not

[876] Accordingly, we decline NYISO's request to clarify that the transmission provider may extend the transmission planning cycle. As explained, we find that three years provides sufficient time to complete the actions necessary to make selection decisions.

[877] Industrial Customers Initial Comments at 15-16, 19-21; NRECA Initial Comments at 18-19, 28; Vistra Initial Comments at 7.

select the relevant Long-Term Regional Transmission Facility (or portfolio of such Facilities). Further, we clarify that transmission providers must conclude a Long-Term Regional Transmission Planning cycle before developing Long-Term Scenarios at the beginning of the next Long-Term Regional Transmission Planning cycle. Given that, as we state directly above, nothing in this final rule prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins, we further find that transmission providers must designate the point in time or action that concludes a Long-Term Regional Transmission Planning cycle. Such designation will ensure transparency regarding whether the transmission providers are engaging in the evaluation and selection of additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle.

382. Some commenters express concern that the proposal to reassess Long-Term Scenarios in concurrent Long-Term Regional Transmission Planning cycles would create uncertainty as to which cycle produced the controlling outcome and would burden stakeholders (e.g., requiring them to provide input on the development of Long-Term Scenarios for the next Long-Term Regional Transmission Planning cycle while also requiring them to provide input on Long-Term Regional Transmission Facilities being considered for selection from the previous Long-Term Regional Transmission Planning

cycle).[878] By providing for a period of up to two years between the date by which transmission providers are required to make a decision to select or not select Long-Term Regional Transmission Facilities and the date by which the next Long-Term Regional Transmission Planning cycle must commence, and by clarifying that transmission providers must conclude one Long-Term Regional Transmission Planning cycle before another begins, this final rule will appropriately minimize confusion regarding overlap between planning assessments. Specifically, this clarification will allow transmission providers to use in subsequent Long-Term Regional Transmission Planning cycles updated base or reference cases that include all Long-Term Regional Transmission Facilities that were selected in a previous Long-Term Regional Transmission Planning cycle, including those not yet in service. We find that including the selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles will improve the accuracy of Long-Term Regional Transmission Planning.

383. In response to WIRES's request,[879] we clarify that transmission providers need not routinely reevaluate selected Long-Term Regional Transmission Facilities. However, we note that, as discussed further in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate

[878] Eversource Initial Comments at 15; ISO-NE Initial Comments at 24; NESCOE Initial Comments at 26.

[879] WIRES Initial Comments at 7.

previously selected Long-Term Regional Transmission Facilities in certain specified circumstances.

384. Given that we are requiring transmission providers in each transmission planning region to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, thus establishing the maximum length of the Long-Term Regional Transmission Planning cycle, we affirm that to the extent that transmission providers believe that a shorter Long-Term Regional Transmission Planning cycle is appropriate for their transmission planning region and circumstances, they may propose on compliance to conduct Long-Term Regional Transmission Planning more frequently than every five years.

385. We find AEP's request to require all transmission planning regions to follow the same-length transmission planning cycles is beyond the scope of this proceeding.[880] In the NOPR, we proposed frequency requirements related to the Long-Term Regional Transmission Planning cycles but did not propose a requirement for transmission providers to align their regional transmission planning cycles with those of the transmission providers in neighboring transmission planning regions.

386. While we do not establish a technical conference after the first Long-Term Regional Transmission Planning cycle, as ELCON requests,[881] the Commission has discretion to conduct additional proceedings at a future date if it finds they are warranted.

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[880] AEP Initial Comments at 5, 8, 14; AEP Reply Comments at 5.

[881] ELCON Initial Comments at 11.

### 3. Categories of Factors

#### a. Requirement to Incorporate Categories of Factors

##### i. NOPR Proposal

387. In the NOPR, the Commission proposed to require transmission providers to incorporate specific categories of factors in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[882] Specifically, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) federal, state, and local laws and regulations that affect the future resource mix and demand;[883] (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and

[882] NOPR, 179 FERC ¶ 61,028 at PP 104-112.

[883] *Id.* P 104 n.189. The Commission explained that "state or federal laws or regulations" meant "enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state, municipality, or at the federal level."

withdrawals; and (7) utility and corporate commitments and federal, state, and local goals[884] that affect the future resource mix and demand.[885]

388. The Commission preliminarily found that incorporating, at a minimum, these categories of factors in the development of Long-Term Scenarios is appropriate because these categories of factors affect the future resource mix and demand, and their incorporation in Long-Term Scenarios is therefore essential to identifying transmission needs driven by changes in the resource mix and demand through Long-Term Regional Transmission Planning.[886] To the extent that transmission providers in a transmission planning region would like to incorporate additional categories of factors in the development of Long-Term Scenarios, the Commission proposed to require that they demonstrate on compliance with any final rule that the incorporation of more than the minimum categories is consistent with or superior to any final rule in this proceeding.[887]

389. Also, as discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Processes section of the NOPR,[888] the Commission proposed to require that transmission providers consider in their Long-Term Regional

[884] *Id.* P 104 n.195. The Commission explained that "goal" meant "any commitment or statement expressed in writing that is not a law or regulation."

[885] *Id.* P 104.

[886] *Id.* P 105.

[887] *Id*.

[888] *Id.* PP 166-174.

Transmission Planning regional transmission facilities that address interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s). The Commission proposed to require that transmission providers incorporate the specific interconnection-related needs identified through that proposed reform, in addition to one or more factors that more generally characterize generator interconnection withdrawals, as a factor in the generator interconnection requests and withdrawals category of factors in their development of Long-Term Scenarios.[889]

390. The Commission explained that incorporation of the categories of factors set forth above in developing Long-Term Scenarios would help facilitate the identification of transmission needs driven by changes in the resource mix and demand, which the Commission preliminarily found was necessary to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates. The Commission explained that absent a requirement to incorporate these categories of factors in the development of Long-Term Scenarios, transmission providers may not incorporate known inputs that likely will affect the future resource mix and demand. Additionally, the Commission explained that transmission providers may not adequately identify transmission needs driven by changes in the resource mix and demand and evaluate the potential benefits of regional transmission facilities that may more efficiently or cost-

[889] *Id.* P 107.

effectively meet such needs. The Commission stated that, as an additional benefit, this requirement would provide clarity to transmission providers and stakeholders regarding which factors must be considered in scenario development.[890]

### ii. Comments

#### (a) Requirement to Incorporate Categories of Factors

391. A number of commenters support the proposal to require transmission providers to incorporate in their development of Long-Term Scenarios the seven specific categories of factors identified in the NOPR.[891] Georgia Commission asserts that these categories of factors adequately capture the factors expected to drive changes in the resource mix and demand,[892] and APPA states that they reflect potential drivers of the need for new transmission.[893]

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[890] *Id.* P 111.

[891] ACEG Initial Comments at 7; Advanced Energy Buyers Initial Comments at 5; AEE Initial Comments at 9-10; Breakthrough Energy Initial Comments at 14; Breakthrough Energy Supplemental Comments at 1; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10-11; Clean Energy Buyers Initial Comments at 14-15; ELCON Initial Comments at 12; Eversource Initial Comments at 16-17; Illinois Commission Initial Comments at 4-5; Kansas Commission Initial Comments at 14-15; Nevada Commission Initial Comments at 8; Northwest and Intermountain Initial Comments at 13; NRECA Initial Comments at 30; OMS Initial Comments at 6; Ørsted Initial Comments at 6; Pacific Northwest State Agencies Initial Comments at 14; PG&E Initial Comments at 6; Pine Gate Initial Comments at 22; PIOs Initial Comments at 17-18; PJM Initial Comments at 6, 64; SEIA Initial Comments at 7; Southeast PIOs Initial Comments at 44-45; US DOE Initial Comments at 11-12.

[892] Georgia Commission Initial Comments at 4.

[893] APPA Initial Comments at 27-28.

392. AEE asks that the Commission clarify that consideration of each factor is mandatory, arguing that failing to take into account any of the seven listed categories of factors would risk under-investment in regional transmission facilities, which could result in unjust and unreasonable rates.[894] Evergreen Action and Pine Gate assert that the Commission should require that the seven factors are "incorporated" instead of "considered" in order to make clear that incorporation is not optional.[895] Otherwise, Pine Gate states, transmission providers may ignore certain categories relevant and critical to identifying needed transmission infrastructure.[896]

393. DC and MD Offices of People's Counsel also urge the Commission to require that all seven factor categories listed in the NOPR be included in Long-Term Scenarios.[897] DC and MD Offices of People's Counsel and ACEG state that the flexibility proposed in the NOPR could give transmission providers the option of not considering the last four factor categories.[898] SEIA recommends that the Commission establish guidelines on the information used to determine factors in the last four factor categories to ensure some level of certainty in how they are reflected in Long-Term Scenarios.[899]

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[894] AEE Initial Comments at 10.

[895] Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22-23.

[896] Pine Gate Initial Comments at 22.

[897] DC and MD Offices of People's Counsel Initial Comments at 11-12.

[898] ACEG Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 11.

[899] SEIA Initial Comments at 9-10.

394. Clean Energy Buyers support the NOPR proposal, arguing that requiring uniform categories of factors across transmission planning regions could promote efficiency and interregional coordination.[900] Southeast PIOs argue that broader consideration of resource trends and other transmission drivers through comprehensive scenarios will inform the decision-making of state authorities tasked with approving transmission facilities.[901] Indicated US Senators and Representatives express general support for proactive transmission planning that considers a broad range of factors.[902]

395. MISO TOs, MISO, and OMS state that existing MISO processes already identify and consider the proposed categories of factors to develop scenarios for transmission planning.[903] MISO TOs further claim that there is no need to require that MISO consider additional factors.[904] OMS supports the NOPR's proposed requirements as to the minimum categories of factors and asserts that the categories of factors proposed in the NOPR are all included in MISO's existing transmission planning processes.[905]

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[900] Clean Energy Buyers Initial Comments at 14-15.

[901] Southeast PIOs Reply Comments at 26.

[902] Indicated US Senators and Representatives Initial Comments at 1.

[903] MISO Initial Comments at 34-35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6.

[904] MISO TOs Initial Comments at 18.

[905] OMS Initial Comments at 6.

396. Some commenters support the NOPR proposal because they note that it provides transmission providers with flexibility as to the specific factors they incorporate into their development of Long-Term Scenarios, as well as how they incorporate those factors.[906]

397. A few commenters support the NOPR proposal to allow transmission providers to incorporate additional categories of factors if they can demonstrate that doing so is consistent with or superior to the final rule.[907] Specifically, AEE states that the Commission should clarify that transmission providers can propose to consider other categories of factors.[908]

398. Pattern Energy states that the Commission should provide examples of how the categories of factors and their associated sensitivities may be modeled to ensure that each Long-Term Scenario is useful for Long-Term Regional Transmission Planning. For example, Pattern Energy asks whether the different scenarios alter the various assumptions for each (or some) of the factors. Alternatively, Pattern Energy asks whether the assumptions remained fixed across scenarios and different scenarios are designed to evaluate different transmission solutions.[909]

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[906] Exelon Initial Comments at 10-11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7.

[907] Acadia Center and CLF Initial Comments at 9; Clean Energy Buyers Initial Comments at 14-15; ELCON Initial Comments at 12; NESCOE Initial Comments at 27; US DOE Initial Comments at 11-12.

[908] AEE Initial Comments at 10.

[909] Pattern Energy Initial Comments at 24.

**(b) Requests for Flexibility**

399. Some commenters argue that the Commission should give transmission providers more flexibility to determine the appropriate categories of factors or individual factors to include in their development of Long-Term Scenarios.[910] NESCOE contends that providing flexibility would be consistent with the Commission's approach in Order No. 1000, where it did not require the identification of transmission needs driven by any particular Public Policy Requirements.[911] PG&E argues that the Commission should allow transmission providers to experiment with how they define scenarios and factors to best reflect the policy and planning environments of their transmission planning regions.[912] EEI notes that not all of the factors listed in the NOPR may be relevant for all transmission planning regions during every long-term assessment and explains that private sector, federal, state, and local public policy goals may diverge or conflict, especially in multi-state regions.[913]

[910] Alabama Commission Initial Comments at 7; APPA Initial Comments at 27-28; Dominion Initial Comments at 25; Indicated PJM TOs Initial Comments at 8-9; MISO Initial Comments at 29; NARUC Initial Comments at 8-9; New York TOs Initial Comments at 11-12; NYISO Initial Comments at 8, 20; Pennsylvania Commission Initial Comments at 5-6; PG&E Initial Comments at 7.

[911] NESCOE Initial Comments at 27-28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

[912] PG&E Initial Comments at 7.

[913] EEI Initial Comments at 12-13.

400. ISO-NE requests that the Commission provide transmission providers with flexibility in the consideration of factors for inclusion in each scenario, noting that the factors may vary from study to study depending on the study objectives. Specifically, ISO-NE argues that the Commission should not require that each Long-Term Scenario account for and consistently reflect the first three categories of factors: federal, state, and local laws and regulations on the future resource mix, decarbonization and electrification, and state-approved integrated resource plans. ISO-NE emphasizes that the Commission should not require local laws to be consistently reflected in and accounted for in Long-Term Scenarios. ISO-NE argues that, in addition to being too prescriptive, such a requirement would introduce unnecessary and substantial administrative burdens and compliance risks with the possibility for inadvertent exclusion of a required law, regulation, or integrated resource plan. Moreover, ISO-NE contends, it would unnecessarily prevent testing of variations with these categories of factors, limiting the usefulness of scenario analysis.[914]

401. Idaho Commission and Idaho Power argue that the NOPR proposal is too prescriptive.[915] PJM advises the Commission not to include too many inflexible details in the implementation of the factors.[916] However, PJM generally supports the NOPR

[914] ISO-NE Initial Comments at 26-27.

[915] Idaho Commission Initial Comments at 3; Idaho Power Initial Comments at 5.

[916] PJM Initial Comments at 67.

proposal to create seven factors that should guide the development of scenarios with some additions and revisions.[917]

402. NYISO states that the Commission should not prescribe specific categories of factors that transmission providers must use and instead should allow each transmission planning region, in coordination with state entities and stakeholders, to determine to what extent and how the seven categories of factors should be applied.[918] SEIA disagrees, asserting that each proposed category of factors is broad enough to reflect regional differences within the category, but suggests that the Commission provide flexibility on implementation details. SEIA explains that the categories of factors do not set forth specific requirements on how much weight each factor should have in each Long-Term Scenario, what generation mix will result from the mix of factors, or what models to use. SEIA states that the Commission should allow transmission providers to include these implementation details in their manuals.[919]

403. Some commenters express support for some or all of the proposed categories of factors but request that the Commission provide transmission providers with flexibility in how they incorporate the factors into their development of Long-Term Scenarios.[920] For

[917] *Id*. at 6, 64.

[918] NYISO Initial Comments at 8, 20.

[919] SEIA Reply Comments at 3-4.

[920] Ameren Initial Comments at 9-12; APPA Initial Comments at 27-28; Arizona Commission Initial Comments at 5; Eversource Initial Comments at 16-17; ISO-NE Initial Comments at 26; LADWP Initial Comments at 3; TANC Initial Comments at 9-10.

example, TANC requests that the Commission allow transmission planning regions, in consultation with stakeholders, to exclude some of the proposed factors (i.e., regulatory and corporate goals or technology trends) from their development of Long-Term Scenarios.[921] TANC also advocates that the Commission should allow transmission planning regions to determine the manner in which other factors, namely trends, resource requirements, generator interconnection requests, and withdrawals, are incorporated in regional transmission planning studies. Although SPP states that most of the categories of factors are appropriate, it contends that requiring the listed factors to be incorporated, rather than considered, in development of Long-Term Scenarios could overburden the process.[922]

404. NEPOOL states that the categories of factors identified in the NOPR seem generic enough to allow implementation despite regional differences or changes in circumstances over time but contends that the Commission should carefully consider different market structures and potential changes to state policies to ensure that any requirement accommodates regional differences.[923] Pine Gate further requests clarification as to the degree of flexibility that the Commission will grant to transmission providers in how they incorporate each factor into Long-Term Scenarios.[924]

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[921] TANC Initial Comments at 9-10.

[922] SPP Initial Comments at 7-8.

[923] NEPOOL Initial Comments at 7.

[924] Pine Gate Initial Comments at 22-23.

### (c) Concerns with the Requirement to Incorporate Categories of Factors

405. Large Public Power argues that the NOPR proposal ignores the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities, as well as Congress' recognition that load-serving entities themselves have a fundamental obligation to build transmission to meet their load.[925] Large Public Power asserts that the NOPR proposal to establish factors that look more broadly than the Commission's core obligations under the FPA threatens to undermine the needs of load-serving entities and their customers.[926] Further, Large Public Power contends that the Commission has no authority to direct the development of transmission facilities.[927] Similarly, some commenters voice concerns with the use of categories of factors to direct transmission investment.[928] Louisiana Commission states that the incorporation of speculative factors would result in a large-scale transmission build-out to accommodate the policy preference of some, at the cost of all.[929]

406. Undersigned States claim that the proposed requirement that each Long-Term Scenario "incorporate and be consistent" with certain factors does not address potentially

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[925] Large Public Power Initial Comments at 19-20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17-18 (quoting 16 U.S.C. 824q(b)(4)), 19-20).

[926] Large Public Power Initial Comments at 20-21.

[927] *Id*. at 11 (citing 16 U.S.C. 824o(i)(2)).

[928] Industrial Customers Initial Comments at 11; Louisiana Commission Initial Comments at 17-19

[929] Louisiana Commission Initial Comments at 17-19.

irresolvable conflicts over how certain factors affect the future resource mix and demand.[930] PPL criticizes the NOPR for failing to explain how to translate the proposed factors into usable assumptions that can feed into transmission planning models, leading to increased uncertainty for transmission developers and greater difficultly in financing transmission projects or gaining siting approval.[931]

### (d) Alternative Frameworks

407. Other commenters propose alternative frameworks for incorporating factors in the development of Long-Term Scenarios. PPL believes that the Commission's proposed categories of factors are largely overlapping and can be summarized and replaced by a single factor: reasonable expectations regarding the future resource mix and demand.[932] ENGIE suggests that, because the Commission's proposed factors may be too numerous for transmission providers to model, certain factors (i.e., laws, regulations, and announced retirements) should be fixed while others are varied or studied as sensitivities (i.e., costs, demand, and resource development trends).[933] PIOs state that the Commission must set minimum requirements for some factors, asserting that there is broad support for minimum requirements.[934]

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[930] Undersigned States Initial Comments at 3.

[931] PPL Initial Comments at 8.

[932] *Id*. at 7.

[933] ENGIE Initial Comments at 3.

[934] PIOs Reply Comments at 10.

408. GridLab contends that the Commission's proposal to require that transmission providers incorporate specific categories of factors in the development of Long-Term Scenarios cannot be enforced and that such broad factors will not change investment outcomes. GridLab states that the proposed list of factors are a helpful minimum standard and recommends that the Commission focus on whether transmission providers have meaningfully incorporated them into Long-Term Regional Transmission Planning.[935] Further, GridLab avers that local laws and regulations and corporate commitments are difficult to incorporate into Long-Term Regional Transmission Planning in a bottom-up, meaningful way.[936] As an alternative, GridLab suggests that transmission providers could use aggregate assumptions and indicative scenario design and allow state and local agencies, as well as other stakeholders, to provide inputs into scenario development, and then evaluate whether the resulting scenarios are consistent with state, local, and corporate commitments.[937]

### iii. Commission Determination

409. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate the seven specific categories of factors proposed in the NOPR, as modified in this final rule, in the development of Long-Term Scenarios. Specifically, as discussed in more detail below, transmission providers must

[935] GridLab Initial Comments at 21-22.

[936] *Id*. at 22.

[937] *Id*.

incorporate in the development of Long-Term Scenarios: (1) federal, federally-recognized Tribal,[938] state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[939] We address each of these categories of factors in the Specific Categories of Factors determination section below.

410. We find that existing regional transmission planning requirements fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.[940] Many commenters in this proceeding, even some that may oppose the prescriptiveness of the requirement or otherwise request more flexibility in how transmission providers account for factors

[938] We emphasize that we are requiring transmission providers to incorporate laws and regulations into Long-Term Scenario development. As noted earlier, while we are providing this opportunity for federally-recognized Tribes to voluntarily participate, we are not imposing any requirements on them to participate.

[939] Modifications to the title of Factor Categories One, Two, Four, and Seven are discussed in the Specific Categories of Factors determination section.

[940] NOPR, 179 FERC ¶ 61,028 at PP 50-51.

affecting Long-Term Transmission Needs,[941] generally agree that the categories of factors outlined in the NOPR account for many of the known determinants of such needs. We find that incorporating the seven categories of factors in the development of Long-Term Scenarios is necessary because these categories of factors are essential to identifying Long-Term Transmission Needs. Further, we find that requiring transmission providers to incorporate the enumerated categories of factors in Long-Term Regional Transmission Planning will help to ensure that transmission providers are accounting for known and identifiable drivers of Long-Term Transmission Needs.

411. We are not persuaded by commenters' arguments that certain of the categories of factors may not be relevant in certain transmission planning regions and therefore that transmission providers should not be required to incorporate those categories of factors in the development of Long-Term Scenarios.[942] We decline to allow transmission providers to exclude some of the proposed categories of factors from being incorporated in the development of Long-Term Scenarios, as certain commenters request, because we conclude that each category of factors includes important determinants of Long-Term Transmission Needs. We are concerned that not requiring incorporation of all of the proposed categories of factors in Long-Term Scenarios would increase the likelihood that transmission providers will continue to underestimate—or omit entirely—certain known

[941] *See, e.g.*, EEI Initial Comments at 12-13; PJM Initial Comments at 64-67.

[942] See, *e.g.*, EEI Initial Comments at 12-13; SPP Initial Comments at 7-8.

determinants of Long-Term Transmission Needs in their regional transmission planning processes.

412. In response to AEE's request, we affirm that the seven categories of factors adopted in this final rule are the minimum set of known determinants of Long-Term Transmission Needs that transmission providers must incorporate into the development of their Long-Term Scenarios, and we decline to adopt the NOPR proposal to require transmission providers to demonstrate on compliance that the incorporation of additional categories of factors is consistent with or superior to any final rule in this proceeding.[943] Transmission providers may be aware of additional categories of factors beyond those adopted in this final rule that drive Long-Term Transmission Needs and, thus, should be incorporated into the development of Long-Term Scenarios. While transmission providers may incorporate additional categories of factors into the development of Long-Term Scenarios, we require in this final rule that each Long-Term Scenario remains plausible, as discussed further below.

413. We clarify that incorporating each category of factors into the development of Long-Term Scenarios means more than merely considering each category of factors in the development of Long-Term Scenarios.[944] Incorporating a category of factors in the development of Long-Term Scenarios means that transmission providers must use factors in the category, for each factor individually or collectively, to determine the assumptions

[943] AEE Initial Comments at 10.

[944] Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22-23.

that will be used in the development of Long-Term Scenarios. Incorporating a category of factors into the development of Long-Term Scenarios does not require exacting precision; transmission providers may generalize how all of the discrete factors in a category of factors will, in the aggregate, affect the development of Long-Term Scenarios.[945] However, we expect that similar factors (or groups of factors) affecting a single assumption used in the development of Long-Term Scenarios will have an additive effect on that assumption.[946] We also expect that incorporating a category of factors into the development of Long-Term Scenarios will result in scenarios that differ from scenarios lacking that specific category of factors; that is, the incorporation of a category of factors should have a measurable impact on the Long-Term Scenario, compared to that same Long-Term Scenario, all else equal, if it had not incorporated that category of factors.

414. We believe that the best-available data requirement, which we adopt and discuss further below, should mitigate concerns that transmission providers may undermine

[945] For example, transmission providers could aggregate the effect of corporate goals by leveraging publicly available surveys of corporations' clean energy and electrification goals and then using those surveys to inform the assumptions used to develop Long-Term Scenarios (e.g., 10% more clean energy resources and 10% higher load growth for a Long-Term Scenario that assumes full achievement of those goals than in a Long-Term Scenario that does not consider such goals).

[946] For example, two independent factors that increase the likelihood of future electric storage resource development (e.g., (1) a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030 and (2) a federal investment tax credit for the deployment of electric storage resources) would have a combined effect that exceeds the effect of either factor alone.

Long-Term Regional Transmission Planning by not incorporating categories of factors in a meaningful way.[947] The best-available data requirement will ensure that the data inputs that transmission providers use to incorporate categories of factors are timely, developed using best practices, and diverse and expert perspectives. We also clarify that, as a consequence of the requirement that all Long-Term Scenarios must be plausible, as well as the requirement that all Long-Term Scenarios must be diverse, both of which we adopt and discuss below, transmission providers must incorporate the categories of factors in the development of Long-Term Scenarios in a way that results in plausible and diverse Long-Term Scenarios.

415. As to the factors within each category that transmission providers must account for when they incorporate each category of factors in the development of Long-Term Scenarios, we require transmission providers to account for the factors that they have determined are likely to affect Long-Term Transmission Needs. As explained above, these Long-Term Transmission Needs include, but are not limited to, evolving reliability concerns and changes in the resource mix, and changes in demand. For each factor (or group of similar factors) within each category of factors that transmission providers identify, in coordination with stakeholders through an open and transparent process as described below, transmission providers must make a determination as to how that factor (or group of similar factors) is likely to affect Long-Term Transmission Needs. Transmission providers must then account for the factors that they have determined are

[947] *E.g.*, ACEG Initial Comments at 28.

likely to affect Long-Term Transmission Needs in the development of the Long-Term Scenarios used in Long-Term Regional Transmission Planning. We clarify, however, that transmission providers in a transmission planning region need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs.

416. We also clarify that a category of factors (e.g., Factor Category Two: federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification) differs from a specific factor (e.g., a specific state law with a decarbonization requirement). We make this distinction because some commenters use only the word "factors" when describing the categories of factors proposed in the NOPR.[948]

417. We disagree with commenters that the categories of factors requirements are too prescriptive,[949] and we believe that the framework adopted in this final rule requiring transmission providers to incorporate categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility. Transmission providers have discretion to determine whether specific factors must be accounted for within each category (i.e., if the specific factor will likely affect Long-Term Transmission Needs), how to account for specific factors in the development

[948] *E.g.*, AEE Initial Comments at 9; Evergreen Action Initial Comments at 4.

[949] ISO-NE Initial Comments at 26; NYISO Initial Comments at 8, 20; PJM Initial Comments at 67.

of Long-Term Scenarios (e.g., the method and data used to forecast resource retirements), and how to vary the treatment of each category of factors across Long-Term Scenarios (e.g., assume all forecasted resource retirements materialize in some but not all Long-Term Scenarios), so long as transmission providers assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities identified in the first three categories of factors—that transmission providers have determined are likely to affect Long-Term Transmission Needs—are fully met (as discussed below). We believe that each proposed category of factors is broad enough to allow the transmission providers in each transmission planning region to reflect regional differences within the category, as noted by SEIA and NEPOOL.[950] In response to PG&E's request that we allow flexibility for transmission providers to use Long-Term Scenarios that best reflect the individual policy and planning environments in their specific transmission planning regions, and to Pattern Energy's questions about how categories of factors may be modeled,[951] we clarify that transmission providers have the flexibility to develop different Long-Term Scenarios specific to their transmission planning region and develop using assumptions based on the categories of factors.

418. In response to NESCOE, we decline to give transmission providers the flexibility to choose which of the proposed categories of factors to incorporate into Long-Term Scenarios, which NESCOE states would be consistent with the flexibility that the

[950] NEPOOL Initial Comments at 7; SEIA Reply Comments at 3-4.

[951] Pattern Energy Initial Comments at 24; PG&E Initial Comments at 7.

Commission provided to transmission providers in Order No. 1000, where it did "not . . . require the identification of any particular transmission need driven by any particular Public Policy Requirements."[952] As noted in The Overall Need for Reform section, there are deficiencies in the Commission's existing regional transmission planning requirements, including that they fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs. We are concerned that, if transmission providers have flexibility to choose which of the proposed categories of factors to incorporate into the development of Long-Term Scenarios, they will continue to underestimate—or omit entirely—certain known determinants of Long-Term Transmission Needs in their regional transmission planning processes. Additionally, we note that transmission needs are distinct from categories of factors: as explained above, categories of factors, and specific factors therein, form the basis for assumptions that will be used in the development of Long-Term Scenarios that transmission providers will then use to identify Long-Term Transmission Needs.

419. We also disagree with arguments that we are directing the development of specific transmission facilities.[953] As an initial matter, transmission providers retain discretion to

[952] NESCOE Initial Comments at 27-28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

[953] *E.g.*, Large Public Power Initial Comments at 20-21; *see also* Alabama Commission Initial Comments at 4; Industrial Customers Initial Comments at 10; Louisiana Commission Initial Comments at 17-19; Pennsylvania Commission Initial Comments at 6.

determine how specific factors will affect Long-Term Transmission Needs. Moreover, the categories of factors requirements adopted in this final rule do not create new transmission needs that did not previously exist, but rather, they improve regional transmission planning processes by requiring transmission providers to identify Long-Term Transmission Needs across a plausible and diverse range of future scenarios and to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. If transmission providers do not account in Long-Term Regional Transmission Planning for known determinants of Long-Term Transmission Needs, then those needs would still exist and would likely be resolved, if at all, in a relatively inefficient or less cost-effective manner (e.g., in a piecemeal fashion through local transmission planning processes and/or generator interconnection processes). We are not requiring that transmission providers select any particular Long-Term Regional Transmission Facility and therefore are not directing the development of any particular transmission facilities. Finally, we clarify that while the requirement for transmission providers to incorporate the seven categories of factors adopted in this final rule into the development of Long-Term Scenarios is intended to ensure that Long-Term Regional Transmission Facilities are identified for selection to more efficiently or cost-effectively address Long-Term Transmission Needs, we do not believe that concerns over whether a transmission provider appropriately implemented this requirement represent an appropriate basis on which to challenge the cost allocation for one or more individual Long-Term Regional Transmission Facilities. Rather, whether the allocation of costs is just and reasonable and not unduly discriminatory is governed by the requirement that

costs be roughly commensurate with benefits, as discussed in the Regional Transmission Cost Allocation section below.

420. We disagree with Large Public Power's argument that we are ignoring the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities.[954] As described below, we are requiring all Long-Term Scenarios to be consistent with and fully account for factors in Factor Category Three, which includes state-approved integrated resource plans and the expected supply obligations of load-serving entities. Therefore, transmission providers are required to plan to meet the needs of load-serving entities.

421. We decline to adopt more specific minimum requirements than those described herein for incorporating categories of factors in the development of Long-Term Scenarios, as requested by some commenters.[955] We believe that the requirements adopted herein, coupled with the other Long-Term Scenarios requirements, including the plausible and diverse and best available data requirements, are sufficiently detailed to address the need for reform without limiting regional flexibility.

[954] Large Public Power Initial Comments at 19-20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17-18 (quoting 16 U.S.C. 824q(b)(4)), 19-20.

[955] *E.g.*, PIOs Reply Comments at 10.

### b. Specific Categories of Factors

#### i. NOPR Proposal

422. In the NOPR, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) federal, state, and local laws and regulations that affect the future resource mix and demand;[956] (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[957]

##### (a) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations That Affect the Future Resource Mix and Demand (Factor Category One)

###### (1) Comments

423. Many commenters support the proposed requirement that each Long-Term Scenario incorporate and be consistent with the federal, state, and local laws and

[956] NOPR, 179 FERC ¶ 61,028 at P 104 n.189. The Commission explained that "state or federal laws or regulations" meant "enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or municipality, or at the federal level."

[957] *Id.* P 104.

regulations that affect the future resource mix and demand.[958] AEE, Clean Energy States, and Acadia Center and CLF argue that laws and regulations implementing clean energy and decarbonization policies will be key drivers in changes to the resource mix and demand.[959] Moreover, AEE notes, 38 states and the District of Columbia have adopted renewable portfolio standards, many of which have been enacted in statute and constitute binding commitments on utilities and retail energy providers.[960] Clean Energy States similarly assert that the 21 states (plus the District of Columbia and Puerto Rico) with 100% clean energy policies account for 42.3% of United States power sales as of 2020, 49.4% of United States customer accounts, and 51% of United States population.[961] Clean Energy States argue that altogether, these states could see an aggregated demand for 800 TWh of new energy generation to meet their targets.

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[958] Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 9-10; Breakthrough Energy Initial Comments at 14; California Commission Initial Comments at 17; Clean Energy Associations Initial Comments at 10-11; Clean Energy States Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Exelon Initial Comments at 10-11; New England for Offshore Wind Initial Comments at 2; OMS Initial Comments at 6; Pacific Northwest State Agencies at Initial Comments at 14; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17-18; WE ACT Initial Comments at 4-5.

[959] Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 10; Clean Energy States Initial Comments at 3.

[960] AEE Initial Comments at 10 (citing Energy Info. Admin., *Renewable Energy Explained, Portfolio Standards* (June 29, 2021), https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php).

[961] Clean Energy States Initial Comments at 3 (citing Clean Energy States Alliance, *100% Energy Collaborative*, https://www.cesa.org/projects/100-clean-energy-collaborative/).

424. AEE, DC and MD Offices of People's Counsel, and SEIA agree that transmission providers should incorporate the effects of federal, state, and local laws and regulations on renewable energy development into development of Long-Term Scenarios.[962] City of New York states that government action that bears the force of law should be reflected in baseline transmission planning studies and not considered as merely one of multiple factors used to develop Long-Term Scenarios.[963]

425. Southeast PIOs argue that concerns that requiring the incorporation of local laws and regulations in the development of Long-Term Scenarios is unduly burdensome are misplaced at this stage because the details of how it will be done will be established during compliance proceedings.[964]

426. PIOs argue that the Commission should require the same level of engagement with Tribal governments as it does with states and that the Commission should clarify that Long-Term Scenarios must incorporate relevant aspects of Tribal policies.[965]

427. Acadia Center and CLF claim that the Commission should clarify that state laws and regulations that affect the future resource mix and demand include state laws and regulations that affect demand management, such as energy efficiency, distributed

[962] AEE Initial Comments at 17-18, 22; DC and MD Offices of People's Counsel Reply Comments at 5-6; SEIA Initial Comments at 7-8.

[963] City of New York Initial Comments at 7.

[964] Southeast PIOs Reply Comments at 26.

[965] PIOs Reply Comments at 15.

generation, flexible load, and demand response because laws and initiatives in this area will also affect transmission needs while providing grid solutions.[966]

428. Center for Biological Diversity states that the Commission must include all Executive Actions, not just laws and regulations, as factors in Long-Term Regional Transmission Planning. Center for Biological Diversity states that allowing transmission providers to decide whether to consider Executive Orders fails to provide stakeholders with the type of clarity that is a goal of the NOPR.[967]

429. As noted above, some commenters oppose the overall categories of factors requirement in this final rule and argue that requiring transmission providers to incorporate certain factors, such as laws and regulations that affect the resource mix, will force transmission providers to settle irresolvable conflicts among state policies and conduct transmission planning that accommodates the policy preferences of some, at the cost of all.[968]

430. Some commenters acknowledge that state laws and regulations may affect the future resource mix and demand but argue against mandatory inclusion such that they cannot discount certain federal, state, and local laws and regulations.[969] Idaho Power

[966] Acadia Center and CLF Initial Comments at 9.

[967] Center for Biological Diversity Initial Comments at 3, 9-12.

[968] Louisiana Commission Initial Comments at 17-18; Undersigned States Initial Comments at 3.

[969] Ameren Initial Comments at 9-10; NESCOE Initial Comments at 27-28; NYISO Initial Comments at 8, 20.

states that the NOPR proposal does not provide transmission providers with the flexibility necessary to create transmission planning regions that span multiple states and could cause non-jurisdictional entities to opt out of regional transmission planning.[970] NYISO states that the final rule should not require transmission providers to assume across all scenarios the full achievement of all federal, state, and local laws and regulations that could drive the need for transmission. NYISO also does not think that the final rule should require the identification of all federal, state, and local laws and regulations that may drive the need for transmission over the 20-year transmission planning horizon, but instead should provide each transmission planning region with flexibility.[971]

431. Although Duke agrees that many of the categories of factors identified in the NOPR capture a minimum list of factors that are expected to drive changes in the resource mix and demand, it does not support the inclusion of local laws and regulations.[972]

**(2) Commission Determination**

432. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category One: federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, in the development of Long-Term Scenarios. We find that the

[970] Idaho Power Initial Comments at 7.

[971] NYISO Initial Comments at 8.

[972] Duke Initial Comments at 13-14.

factors in this category have been, and will continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. Accordingly, we find that failing to account for factors in Factor Category One would hamper the identification, evaluation, and selection of Long-Term Regional Transmission Facilities that are potentially more efficient or cost-effective solutions to Long-Term Transmission Needs.

433. We clarify that factors in Factor Category One include, among other things, legally binding obligations, incentives (e.g., tax credits), and/or restrictions promulgated by policymakers that will affect new or existing generators, or demand. Further, as discussed in the Additional Categories of Factors section below, we recognize that energy equity and justice laws and regulations are also potential factors within Factor Category One to the extent that they are likely to affect Long-Term Transmission Needs.

434. As discussed in further detail below in the Additional Categories of Factors section, we modify the NOPR proposal for Factor Category One to include federally-recognized Tribal laws and regulations affecting the resource mix and demand because we are persuaded by commenters that contend that such factors have a similar potential to affect Long-Term Transmission Needs as federal, state, and local laws and regulations. Federally-recognized Tribal laws and regulations mean the legally binding obligations, incentives, and/or restrictions promulgated by federally-recognized Tribes that will affect new or existing generators, or demand. We make similar modifications to Factor Category Two and Factor Category Seven, as discussed in the Factor Category Two and Factor Category Seven sections below.

435. We are not persuaded by Louisiana Commission's argument that requiring transmission providers to incorporate certain factors, such as federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, would result in a transmission buildout that only accommodates the policy preferences of some stakeholders, at the cost of all transmission customers.[973] Similarly, we are not persuaded by Undersigned States' contention that policy differences among states may be irresolvable, and therefore the Commission should not require transmission providers to account for laws and regulations in their Long-Term Scenarios.[974] First, every policy choice—from federal tax incentives and state regulation of generation, down to local economic development policies—that changes the quantity and location of generation and load contributes to changes in transmission needs. Accordingly, all transmission buildout—whether it occurs through a local or regional transmission plan, or through a near-term transmission planning process or a more forward-looking one—is a reflection, at least in part, of federal, federally-recognized Tribal, state, and local laws and regulations that drive transmission needs. Rather than a unique feature of Long-Term Regional Transmission Planning, transmission planning of any kind will inherently reflect the policy choices of multiple decisionmakers, because the quantity and location of generation and load are shaped by multiple decisionmakers.

[973] Louisiana Commission Initial Comments at 17.

[974] Undersigned States Initial Comments at 3.

436. Second, we find that requiring transmission providers to properly account for known determinants of Long-Term Transmission Needs is necessary to ensure just and reasonable rates. Specifically, because, as described above, Long-Term Transmission Needs driven by disparate policy decisions would continue to exist, regardless of whether they were identified in Long-Term Regional Transmission Planning, failing to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs will result in unjust and unreasonable rates. We note that some policy decisions are reflected in laws and regulations, which can affect load-serving entities' supply obligations, and in transmission planning regions with vertically integrated utilities, some policy decisions are reflected in the integrated resource plans approved by retail regulators.

437. We are not endorsing the merits of any specific federal, federally-recognized Tribal, state, or local laws and regulations or of any specific state-approved integrated resource plans. We emphasize that the Commission's policies are technology neutral, and we are not establishing a preference for certain types of generation or energy end uses. We acknowledge that, in some instances, a policy choice in one jurisdiction may reduce or negate the effect of a policy choice in another jurisdiction. However, the fact that certain factors may have conflicting effects on Long-Term Transmission Needs is not a basis to conclude that the effects of laws and regulations or state-approved integrated resource plans should be ignored or discounted.

### (b) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations on Decarbonization and Electrification (Factor Category Two)

#### (1) Comments

438. Several commenters support the proposed requirement that Long-Term Scenarios incorporate federal, state, and local laws and regulations on decarbonization and electrification.[975] Illinois Commission notes that, in Illinois, the Climate and Equitable Jobs Act of 2021 will affect future demand and the supply mix and that Long-Term Regional Transmission Planning will be critical to meeting Illinois' policy goals.[976] New England for Offshore Wind states that electrification to meet New England states' greenhouse gas emissions mandates will dramatically increase electricity load and require massive amounts of clean energy.[977] Pattern Energy states that federal and state legislative efforts to promote decarbonization should be the basis of scenario modeling for generation and demand.[978] Center for Biological Diversity states that the Commission should identify decarbonization as an objective in Long-Term Regional Transmission

[975] Acadia and CLF Initial Comments at 9; Center for Biological Diversity Initial Comments at 7-9; Clean Energy Associations Initial Comments at 10-11; DC and MD Offices of People's Counsel Reply Comments at 6; Illinois Commission Initial Comments at 4-5; New England for Offshore Wind Initial Comments at 2-3; Pacific Northwest State Agencies at Initial Comments at 14; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17-18; Renewable Northwest Initial Comments at 19-22.

[976] Illinois Commission Initial Comments at 4-5.

[977] New England for Offshore Wind Initial Comments at 2-3.

[978] Pattern Energy Initial Comments at 26.

Planning because it has the authority and responsibility to prioritize decarbonization in the transmission planning process since these policies bear directly on the provision of transmission service.[979]

439. Nevada Commission acknowledges that other state policies and its own integrated resource planning process should be considered in Long-Term Regional Transmission Planning even though it does not support other state policies affecting Nevada ratepayers.[980] Utah Division of Public Utilities states that the impact of state policies should be part of the Long-Term Regional Transmission Planning scenario analysis.[981] Cypress Creek asserts that the Commission should include state policy requirements in a uniform set of assumptions that are applicable across all Long-Term Scenarios.[982]

**(2) Commission Determination**

440. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Two: federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification, in the development of Long-Term Scenarios. Similar to Factor Category One, we find that the factors in this category have been, and will

[979] Center for Biological Diversity Initial Comments at 7-9 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 89-93).

[980] Nevada Commission Initial Comments at 8.

[981] Utah Division of Public Utilities Reply Comments at 4.

[982] Cypress Creek Reply Comments at 5-6.

continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. We clarify that this category of factors includes legally binding obligations, incentives, and/or restrictions that affect Long-Term Transmission Needs in different ways than Factor Category One, for example, by limiting the carbon intensity of electricity generation or electrifying energy end uses and thereby significantly increasing electricity use in certain sectors of the economy, such as transportation and building heating and cooling. We acknowledge that there could be overlap between Factor Categories One and Two because a certain law or regulation could reasonably be considered to fit into both categories. In such a circumstance, transmission providers must account for the law or regulation in one of the two categories, not both, to avoid double-counting of that factor's anticipated effect on Long-Term Transmission Needs. Since transmission providers must account for and be consistent with, and not discount, factors in the first three categories of factors equally once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs, we do not believe it is necessary to ensure that a certain factor is considered as part of Factor Category One instead of Factor Category Two (or vice versa), but rather it is only necessary to ensure that these factors are accounted for in the development of Long-Term Scenarios.

441. In addition, based on the record before us, we modify the NOPR proposal for Factor Category Two to include federally-recognized Tribal laws and regulations on decarbonization and electrification because we are persuaded by commenters that argue

that such factors have the same potential to affect Long-Term Transmission Needs as federal, state, and local laws and regulations on decarbonization and electrification.

442. Similar to our response in the Factor Category One section to commenters arguing that categories of factors involving federal, federally-recognized Tribal, state, and local laws and regulations would provide preference to some at the cost of all or result in irresolvable conflict,[983] we find that differences in if and how government entities promulgate laws and regulations concerning decarbonization and electrification (i.e., factors in Factor Category Two) do not diminish the effect of such laws and regulations. As such, Long-Term Scenarios must account for these key drivers of Long-Term Transmission Needs so that transmission providers can identify such needs through Long-Term Regional Transmission Planning and can identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs.

### (c) State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three)

#### (1) Comments

443. Several commenters support the proposed requirement that each Long-Term Scenario incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities.[984] NRECA and TAPS state that using Long-Term

[983] Louisiana Commission Initial Comments at 17-19; Undersigned States Initial Comments at 3. Comments originally summarized in PP 404-405.

[984] California Commission Initial Comments at 17; NRECA Initial Comments at 30; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17-18; US Chamber of

Scenarios that satisfy expected load-serving entity supply obligations is consistent with FPA section 217(b)(4)'s directive to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.[985] NRECA asserts that this category should be moved to the top of the list of categories of factors because state-approved integrated resource plans and load-serving entity supply obligations will incorporate state laws and regulations affecting resource mix, demand, decarbonization, and electrification. Additionally, NRECA contends that the changing characteristics of the distribution grid, such as distributed energy resources, storage, demand response, energy efficiency, and electrification of demand, will affect load-serving entity needs and should be incorporated in this category of factors.[986] Clean Energy Associations and ACEG agree.[987]

444. APPA and ACEG argue that the final rule should focus on the resource plans of load-serving entities and include a requirement for transmission providers to include in their Long-Term Regional Transmission Planning process a requirement to coordinate with load-serving entities.[988] ACEG argues that such a requirement is necessary because

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Commerce Initial Comments at 6-7.

[985] NRECA Initial Comments at 30-31; TAPS Initial Comments at 2, 7-8 (citing NOPR, 179 FERC ¶ 61,028 at P 106); *see also* APPA Initial Comments at 28.

[986] NRECA Initial Comments at 30-31 n.85.

[987] ACEG Reply Comments at 22; Clean Energy Associations Reply Comments at 6-7.

[988] ACEG Reply Comments at 22; APPA Initial Comments at 27-28.

not all load-serving entities either own generation or are overseen by a state regulator, meaning that they must rely on the Commission to ensure that transmission planning meets their needs.[989]

445. Several commenters clarify that they support the inclusion of load-serving entity demand as a factor in Long-Term Scenarios.[990] In addition, some commenters support the inclusion of load-serving entity generation resource planning as a factor in Long-Term Scenarios.[991] PIOs argue that the Commission should require load-serving entities to provide their generation and demand forecasts to transmission planning entities.[992] ACEG agrees and argues that PIOs' recommendation will decrease the burden on transmission planning entities and provide them with the information they need to determine the future resource mix.[993]

446. Entergy asserts that the Commission has identified the appropriate factors but explains that not all states conduct commission proceedings related to integrated resource plans and, for those states that do, the timelines are not necessarily the same. Thus,

[989] ACEG Reply Comments at 22-23.

[990] ACEG Reply Comments at 22-23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4; PIOs Initial Comments at 18; PIOs Reply Comments at 10.

[991] ACEG Reply Comments at 22-23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4.

[992] PIOs Initial Comments at 19.

[993] ACEG Reply Comments at 23.

Entergy requests that the Commission clarify that the term "state-approved utility integrated resource plans" will be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning. Entergy asserts that such clarification would result in a range of benefits such as consistency of data with current local, state, and federal laws and expected retirements, additions, and corporate goals.[994]

**(2) Commission Determination**

447. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Three: state-approved integrated resource plans and expected supply obligations for load-serving entities, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Three because it reflects the outcomes of retail-level regulatory proceedings that will affect Long-Term Transmission Needs. Further, incorporation of Factor Category Three into Long-Term Scenarios will ensure that transmission providers properly account for resource planning and anticipated changes to demand, including increased integration of distributed energy resources. We note that the Commission shares concurrent jurisdiction over the bulk power system with retail regulators,[995] and we agree with commenters that note that FPA section 217(b)(4) directs

[994] Entergy Initial Comments at 15-16.

[995] *Compare* 16 U.S.C. 824d(a) (providing the Commission authority to regulate the rates charged by public utilities in connection with the transmission or wholesale sale

the Commission to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.[996]

448. In response to commenters that note some retail regulators may review but not formally approve integrated resource plans, we clarify that, for this category of factors, state-approved integrated resource plans includes resource plans that are developed and reviewed through a retail proceeding in jurisdictions where the retail regulator does not formally approve such plans.[997] We grant Entergy's clarification request that the term "state-approved utility integrated resource plans" be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning because it would enable a more complete consideration of state-approved integrated resource plans and expected supply obligations for load-serving entities.

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of electric energy), *with id.* 824(a) (reserving certain state authorities).

[996] 16 U.S.C. 824q(b)(4) ("The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.").

[997] Entergy Initial Comments at 15-16.

449. In response to APPA and ACEG's request for the Commission to require transmission providers to coordinate with load-serving entities,[998] we note that we require transmission providers, as described in further detail below, to provide an open and transparent process in their OATT that provides stakeholders, including load-serving entities, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.[999] However, in response to PIOs' request that the Commission require load-serving entities to provide their generation and demand forecast to transmission providers, we agree that such information will assist transmission providers in developing Long-Term Scenarios. Therefore, consistent with the information exchange transmission planning principle established in Order No. 890,[1000] we require load-serving entities that are taking transmission service pursuant to an OATT to provide transmission providers with

[998] ACEG Reply Comments at 22; APPA Initial Comments at 27-28.

[999] *See infra* Stakeholder Process and Transparency section.

[1000] The information exchange transmission planning principle requires network transmission customers to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load. Point-to-point transmission customers are required to submit their projections for need of service over the planning horizon and at what receipt and delivery points. To the extent applicable, transmission customers should also provide information on existing and planned demand resources and their impact on demand and peak demand. Transmission providers, in consultation with their customers and other stakeholders, must develop guidelines and a schedule for the submittal of such customer information. Order No. 890, 118 FERC ¶ 61,119 at PP 486-487.

information on the load-serving entities' projected loads and resources over the planning horizon.

### (d) Trends in Technology and Fuel Costs Within and Outside of the Electricity Supply Industry, Including Shifts Toward Electrification of Buildings and Transportation (Factor Category Four)

#### (1) Comments

450. Several commenters emphasize the importance of incorporating assumptions regarding shifts towards electrification in Long-Term Scenarios.[1001] Clean Energy Buyers assert that regional flexibility should not be used to diminish the representation in Long-Term Scenarios of significant load growth from the commercial and industrial sectors and electrification of transportation.[1002] Likewise, DC and MD Offices of People's Counsel assert that regional flexibility should be reflected in the actual inputs for these factors, rather than their inclusion in or exclusion from Long-Term Scenarios, noting, for example, that electrification forecasts in some areas are increasing load growth estimates by 30%.[1003] Clean Energy Associations argue that, to keep pace with changes in supply and demand, Long-Term Scenarios should incorporate aging

[1001] Clean Energy Associations Initial Comments at 11; Clean Energy Buyers Initial Comments at 15-16; DC and MD Offices of People's Counsel Initial Comments at 11-12; ENGIE Initial Comments at 3; PJM Market Monitor Initial Comments at 3.

[1002] Clean Energy Buyers Initial Comments at 15-16.

[1003] DC and MD Offices of People's Counsel Initial Comments at 11-12.

infrastructure and planned replacements, along with load and generation trends informed by both historical data and applicable policy drivers.[1004]

451. Other commenters emphasize the trends in specific technology costs, such as long-duration storage. ENGIE states that advances in longer-duration storage and advancing photovoltaic technologies may affect the ability to develop resources in areas previously considered to be uneconomic, which could affect the resource and demand mix.[1005] Form Energy argues that the inclusion of diverse, long-duration electric storage technologies would require significantly fewer new transmission needs.[1006]

452. Pine Gate supports the inclusion of trends in technology and fuel costs in Long-Term Scenarios; however, Pine Gate requests that the Commission clarify what type of data would constitute a "trend" and how it expects transmission providers to assure that trend-related input is objective and representative of the "best available data."[1007] Similarly, US DOE recommends that the Commission clarify whether the term "trends in technology and fuel costs" refers to trends in fuel cost and trends in technology, or rather trends in the cost of fuel and trends in the cost of technology. If the Commission is referring to the former, US DOE recommends that the Commission consider the phrase "trends in fuel costs and in the cost, performance, and availability of generation, storage,

[1004] Clean Energy Associations Initial Comments at 12.

[1005] ENGIE Initial Comments at 3.

[1006] Form Energy Initial Comments at 2-3.

[1007] Pine Gate Initial Comments at 24.

and transmission technologies." US DOE further recommends that the Commission provide a non-exhaustive list of examples of cost and technology trends that transmission planners could consider.[1008]

453. SEIA recommends that the Commission direct transmission providers to use the data and models used in NREL's Electrification Futures Study, Solar Futures Study, Storage Futures Study, and Transportation Futures Study.[1009] PIOs disagree with granting discretion to transmission providers to define trends in technology and fuel costs because PIOs state that it could empower them to distort the modeling process and create Long-Term Scenarios that are meaningless.[1010]

454. PIOs argue that the Commission should require transmission providers to use certain values for trends in technology and fuel costs within and outside of the electricity supply industry.[1011]

455. New York TOs argue that trends in technology costs are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider.[1012] Similarly, PPL criticizes the Commission's proposed requirement that transmission providers forecast trends in technology without providing concrete assumptions to use, or

[1008] US DOE Initial Comments at 12-13.

[1009] SEIA Initial Comments at 10.

[1010] PIOs Initial Comments at 19.

[1011] *Id*. at 17-19.

[1012] New York TOs Initial Comments at 11-12.

without a guarantee for cost recovery for investments that are based on those uncertain forecasts.[1013]

**(2) Commission Determination**

456. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Four: trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Four into the development of Long-Term Scenarios because the relative cost of constructing and operating different types of generation or storage resources and the relative cost of electrifying certain energy end uses will affect Long-Term Transmission Needs. We further find that this requirement is necessary to ensure that transmission providers develop plausible Long-Term Scenarios that account for technological changes expected over the transmission planning horizon, facilitating transmission providers' identification of Long-Term Transmission Needs.

457. As requested by commenters, including US DOE, we modify this category of factors in the final rule to clarify that this category of factors is meant to capture changes in the cost, as well as the performance and availability, of certain technologies relevant to the electric industry.[1014] In response to commenters arguing that trends in technology

[1013] PPL Initial Comments at 8.

[1014] Pine Gate Initial Comments at 24; US DOE Initial Comments at 12.

costs are amorphous and should not be included in the final rule as a required category of factors, we disagree. However, as discussed above, we grant transmission providers discretion to determine whether specific trends identified in Factor Category Four are likely to affect Long-Term Transmission Needs and how to account for those specific trends in Long-Term Scenarios.[1015] As discussed in further detail below, transmission providers also have some discretion to discount or place more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category.

458. In response to comments from US DOE,[1016] we clarify that trends in fuel costs and in the cost, performance, and availability of generation, storage, and building and transportation electrification technologies may include, but are not limited to, cost and technology trends for: utility-scale generation construction costs for different generating technologies; distributed energy resources; storage technologies with differing duration limitations; carbon capture and sequestration; small modular nuclear; light-, medium-, and heavy-duty electric vehicles and electric vehicle supply equipment; and ground- and air-source heat pumps. While we agree with US DOE that transmission providers should consider trends in the cost, performance, and availability of transmission technologies as part of their evaluation of potential solutions to Long-Term Transmission Needs, we do not believe that these trends should be included as factors in this category because trends in the cost, performance, and availability of transmission technologies do not drive Long-

[1015] *See* New York TOs Initial Comments at 11-12; PPL Initial Comments at 8.

[1016] US DOE Initial Comments at 12-13.

Term Transmission Needs. We also agree with commenters that note that the effects of the factors in this category may vary significantly, such as shifts towards electrification leading to significant load growth, or cost reductions for emerging technologies, like long-duration electric storage resources, mitigating some new transmission needs.

### (e) Resource Retirements (Factor Category Five)

#### (1) Comments

459. Several commenters support the proposed requirement that each Long-Term Scenario incorporate resource retirements as a category of factors.[1017] PJM Market Monitor states that PJM faces the potential for the retirement of large coal resources and that the PJM capacity market design and the transmission planning process need to identify these specific resources well in advance and ensure an efficient response to obviate the need for nonmarket cost-of-service contracts to retain generation while transmission is constructed.[1018]

460. PIOs and NYISO both argue that the Commission should further specify that transmission providers must incorporate expected trends in resource retirements rather

[1017] Breakthrough Energy Initial Comments at 14; NRECA Initial Comments at 31; NYISO Initial Comments at 24; PIOs Initial Comments at 21; SPP Market Monitor Initial Comments at 9; *see also* PJM Market Monitor at 3 ("PJM faces the potential retirement . . . of a significant amount of coal resources in the next five years. Both the PJM capacity market and design and the transmission planning process need to identify these specific resources well in advance and plan for their retirement in order to ensure an efficient response and to obviate the need for nonmarket cost of service contracts to retain the generation while transmission is constructed.").

[1018] PJM Market Monitor Initial Comments at 3.

than just announced retirements into Long-Term Scenarios.[1019] PIOs state the Commission should require transmission providers to (1) specify how they will use generator age and condition data to predict retirements, (2) include announced retirements, and (3) specify how they will reflect trends and incentives for distributed energy resources, as well as how they will quantify these trends.[1020]

461. NYISO states that the final rule should confirm that each transmission planning region has the authority and flexibility to account for likely resource retirements that have not been announced by the resource based on factors that include the facility's age, its emission profile, applicable laws and regulations, and other factors.[1021] Similarly, Pine Gate asserts that resource retirements should be included at the earliest opportunity as there is often a significant gap of time between when a public announcement is made and when the official notice of deactivation is communicated to the transmission provider.[1022]

462. SEIA states that transmission providers should only be required to include the retirement of resources that have provided notice of pending retirement pursuant to the applicable tariff provisions.[1023] PJM supports engaging in transparent economic impact analyses of generation resource retirements but asserts that such analyses might disclose

[1019] NYISO Initial Comments at 24; PIOs Initial Comments at 21.

[1020] PIOs Initial Comments at 21.

[1021] NYISO Initial Comments at 24.

[1022] Pine Gate Initial Comments at 24.

[1023] SEIA Initial Comments at 10.

confidential information about specific generators. Therefore, PJM contends that the Commission will need to provide clear direction on how it wishes to address these issues, especially since masking of data is not a practical solution once the transmission case is released.[1024]

**(2) Commission Determination**

463. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Five: resource retirements, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Five because resource retirements expected over the transmission planning horizon will affect Long-Term Transmission Needs. Commenters generally support requiring this category of factors, but commenters disagree as to how transmission providers should account for projected resource retirements that have not been publicly announced.[1025]

464. In response to those commenters, we clarify that, to develop plausible Long-Term Scenarios, transmission providers must, in incorporating Factor Category Five into the development of Long-Term Scenarios, account for likely resource retirements beyond those that have been publicly announced. The record indicates that resource retirements have significantly influenced the supply of electricity in the past and are expected to do

[1024] PJM Initial Comments at 6, 69.

[1025] NYISO Initial Comments at 24; Pine Gate Initial Comments at 24; PIOs Initial Comments at 21.

so in the coming decades.[1026] The North American Electric Reliability Corporation's 2021 Long-Term Reliability Assessment reports nearly 50 GW of confirmed thermal generation resource retirements by 2026 and acknowledges that many more are yet to be announced.[1027] In addition, the record reflects that publicly announced resource retirements are only a fraction of the resource retirements expected over the required 20-year transmission planning horizon.[1028] Given the significance of resource retirements, and the limited scope of publicly announced resource retirements, we find that transmission providers must account for expected retirements that have not been publicly

[1026] *See supra* note 241; Colorado Consumer Advocate Initial Comments, attach. 7 (US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (Aug. 2017)) at 13-14 (stating that 132 GW of generation capacity retired between 2002 and 2016 – approximately 15% of the installed capacity in 2002 – due to the advantaged economics of natural gas-fired generation, low electricity demand growth, the deployment of variable energy resources, and regulatory requirements); *see also, e.g.*, AEP Initial Comments at 4 n.12.

[1027] SEIA Initial Comments at 9 (citing North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment*, at 30, 35 (Dec. 2021)). The North American Electric Reliability Corporation states that long-range retirement projects based on confirmed retirements could be "significantly understated" because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas. The North American Electric Reliability Corporation 's 2021 reported retirements through 2026 increased 126% compared to the North American Electric Reliability Corporation's 2020 estimates; and the North American Electric Reliability Corporation's 2022 reported retirements through 2026 increased compared to the North American Electric Reliability Corporation 's 2021 retirements. *See* North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment*, at 35 (Dec. 2021); NERC, *2022 Long-Term Reliability Assessment*, at 17 (Dec. 2022).

[1028] For example, announced retirements account for less than half of MISO's projected retirements over a 20-year transmission planning horizon. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report*, at 14-19, (Dec. 2021), https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf).

announced to meet this final rule's requirement that transmission providers develop a plausible set of Long-Term Scenarios.[1029]

465. We provide flexibility to transmission providers to propose on compliance with this final rule how to account for resource retirements that might take place over the transmission planning horizon, in addition to those that have been publicly announced. We note, for example, that transmission providers could propose to account for expected retirements by considering factors such as a generating facility's age, its emissions profile, its projected costs and revenues, and any applicable laws and regulations that may affect a generating facility's continued operation over the transmission planning horizon.[1030] To the extent that certain laws and regulations identified by stakeholders in Factor Categories One and Two will necessitate the retirement of certain resources, we reiterate that transmission providers must develop Long-Term Scenarios that are consistent with such laws and regulations.

466. In response to PJM's concerns that conducting transparent economic impact analyses of generation resource retirements could lead to the disclosure of confidential

[1029] *See infra* Types of Long-Term Scenarios section.

[1030] For example, MISO assumes age-based resource retirements which vary by resource type and scenario, over a 20-year transmission planning horizon. In a 2021 study, MISO assumes coal-fired resources will retire at age 46 in one scenario, and age 36 in another. MISO assumes utility-scale solar resources will retire at age 25 in every scenario. MISO also incorporates resource retirements announced by the resource owner, stated in an integrated resource plan, or filed in MISO's Attachment Y. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report*, at 14-19, (Dec. 2021), https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf).

information about specific generators, we note that the Commission has previously acknowledged that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.[1031] We note that we are not specifying how transmission providers must estimate resource retirements, and we clarify that transmission providers may include what they believe to be appropriate confidentiality protections in their proposals to account for resource retirements that might take place over the transmission planning horizon. The Commission will evaluate those proposals by using the established principles in Order No. 890,[1032] as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

### (f) Generator Interconnection Requests and Withdrawals (Factor Category Six)

#### (1) Comments

467. Several commenters support the proposed requirement that each Long-Term Scenario incorporate generator interconnection requests and withdrawals.[1033] Pattern Energy argues that generation interconnection queues are indicative of the market for

[1031] *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227, at P 20 (2011).

[1032] Order No. 890, 118 FERC ¶ 61,119 at PP 471-476.

[1033] Breakthrough Energy Initial Comments at 14; Cypress Creek Reply Comments at 5-7.

generation capacity additions and should also be a major source for generation assumptions in both near-term and long-term scenario planning.[1034] SEIA supports the proposed requirement with the caveat that transmission providers should only include interconnection customers that have signed a facilities study agreement, or other applicable study agreement.[1035] Cypress Creek asserts that the Commission should require transmission providers to include the proposed generator interconnection requests in the queue that have completed a system impact study as part of a uniform set of assumptions applicable across all scenarios.[1036]

468. CAISO and MISO state that their regional transmission planning processes already include projects in the generator interconnection queue.[1037] MISO further explains that it considers the generator interconnection queue when determining the location where future generation will interconnect, but MISO also states that transmission providers and their stakeholders need to have flexibility, including how to consider trends in interconnection queue requests.[1038] Further, MISO argues that "generation interconnection requests and withdrawals" as stated in the NOPR is unclear regarding how the transmission provider must weigh withdrawals differently than requests.

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[1034] Pattern Energy Initial Comments at 26.

[1035] SEIA Initial Comments at 10.

[1036] Cypress Creek Reply Comments at 5-7.

[1037] CAISO Initial Comments at 34; MISO Initial Comments at 35.

[1038] MISO Initial Comments at 35-36.

Therefore, MISO requests that the Commission revise the NOPR proposal to require transmission providers to "consider activity in the generation interconnection queue."[1039]

469. Nebraska Commission asserts that the Commission should not include interconnection request withdrawals as a factor because it does not follow the Commission's cost causation principles and would incentivize additional interconnection requests. For example, Nebraska Commission states, most interconnection requests in SPP are duplicative, and entities compare costs among their requests once they are analyzed. Nebraska Commission asserts that such requests could be used to game the transmission planning process, create additional backlogs in the interconnection queue, and shift costs from interconnection customers to transmission customers.[1040]

470. Likewise, Omaha Public Power claims that, until generator interconnection reform is enacted, the use of interconnection queues and withdrawals as factors will lead to scenario inaccuracy due to the size of interconnection backlogs and speculative nature of many queued projects.[1041] Dominion also opposes using the number and size of interconnection requests as a basis for transmission planning because speculative interconnection requests could stimulate transmission development in areas slated for development by private interests.[1042]

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[1039] *Id*. at 36.

[1040] Nebraska Commission Initial Comments at 4-5.

[1041] Omaha Public Power Initial Comments at 3.

[1042] Dominion Reply Comments at 7-8.

471. PJM Market Monitor states that, while there are many comments on the significant renewable resources PJM will connect to its grid, based on historic completion rates and effective load carry capability derate factors, only 5.6% of renewable resources are expected to go into service.[1043]

**(2) Commission Determination**

472. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Six: generator interconnection requests and withdrawals, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Six because generation interconnection queues provide important information about future generation development over the transmission planning horizon and therefore affect Long-Term Transmission Needs. Multiple RTOs/ISOs explain that their regional transmission planning processes already account for generation projects in the interconnection queue, but MISO notes that transmission providers need flexibility in how to incorporate that data into the development of Long-Term Scenarios.[1044] In response to MISO's concerns, we reiterate that transmission providers have discretion to determine how to account for all factors, including interconnection requests and withdrawals, in Long-Term Scenarios.

[1043] PJM Market Monitor Initial Comments at 4.

[1044] MISO Initial Comments at 35-36

473. We disagree with commenters that argue that, because many interconnection requests are speculative and/or duplicative, requiring transmission providers to incorporate Factor Category Six into the development of Long-Term Scenarios will compromise the accuracy of Long-Term Scenarios, shift costs to transmission customers that should be borne by interconnection customers, or create an incentive for additional interconnection requests that could slow down interconnection queue processing.[1045] We note that over the years, and recently with Order No. 2023, transmission providers and the Commission have adopted changes to generator interconnection procedures to reduce the submission of speculative interconnection requests in the interconnection queue. For example, interconnection requests require significant financial commitments from the interconnection customer (e.g., application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023.[1046] Noting that, as discussed above, transmission providers will have discretion as to how they account for factors in Long-Term Scenarios and may determine whether certain generator interconnection requests are speculative and/or duplicative, such that the requests are unlikely to affect Long-Term Transmission Needs, and then make corresponding adjustments to their Long-Term Scenarios. As discussed in further detail below, transmission providers can also account for uncertainty by discounting or putting

[1045] Dominion Reply Comments at 7-8; Nebraska Commission Initial Comments at 4-5; Omaha Public Power Initial Comments at 3.

[1046] Order No. 2023, 184 FERC ¶ 61,054 at P 490.

more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category. Additionally, we believe that the existence of a large number of interconnection requests in a certain area, even if some of those requests are speculative, indicates that generation developers have an interest in interconnecting resources in that area, which Long-Term Scenarios should take into account.

### (g) Utility and Corporate Commitments and Federal, Federally-Recognized Tribal, State, and Local Policy Goals that Affect Long-Term Transmission Needs (Factor Category Seven)

#### (1) Comments

474. Some commenters generally support the proposed requirement to incorporate in Long-Term Scenarios utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[1047] ACEG contends that FPA section 217(b)(4) supports the Commission's proposed requirement to include public policies and utility and corporate renewable procurement goals within Long-Term Scenarios because load-serving entities' service obligations will depend upon both public

[1047] ACEG Initial Comments at 26-29; AEE Initial Comments at 10-11; Advanced Energy Buyers Initial Comments at 5-6; Amazon Initial Comments at 3-4; Center for Biological Diversity Initial Comments at 9-12; Environmental Groups Supplemental Comments at 2; Ørsted Initial Comments at 7; Pacific Northwest State Agencies at Initial Comments at 14; PIOs Initial Comments at 18-19; SEIA Initial Comments at 10; SREA Initial Comments at 41-46; *see also* Environmental Groups Supplemental Comments at 2 ("The electric industry is undergoing a major transformation driven by consumer, utility, and corporate preferences, state public policies, and the cost competitiveness of renewable energy. The Commission's transmission planning and cost allocation standards must be up to the challenge of enabling this transition while ensuring the continued provision of reliable and affordable electricity at just and reasonable rates.").

policies and the resource preferences of their customers.[1048] AEE highlights the role of local goals by noting that 29 of the 50 most populous cities in the United States have set clean or renewable energy targets.[1049]

475. Advanced Energy Buyers argue that private efforts to use more low- and zero-carbon electricity are significantly affecting the resource mix and in turn transmission needs, noting that since 2014, commercial and industrial customers have contracted for more than 52 GW of clean energy in the United States, with annual increases every year since 2016.[1050] Moreover, Advanced Energy Buyers state, corporate and industrial customer demand for renewable energy in the United States is expected to reach about 85 GW by 2030.[1051] Advanced Energy Buyers state that, in some markets, corporate demand is already a dominant driver of renewable energy deployment, as in Illinois, where corporate procurement accounted for roughly one-third of total renewable deployment.[1052] SEIA states that, for corporate commitments, transmission providers

[1048] ACEG Initial Comments at 26-29.

[1049] AEE Initial Comments at 10-11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets).

[1050] Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers Alliance, *State of the Market 2022*, https://cebuyers.org/state-of-the-market/).

[1051] *Id.* at 5-6 (citing Wood Mackenzie, *Corporates Usher in New Wave of US Wind and Solar Growth* (Aug. 2019), https://www.woodmac.com/our-expertise/focus/Power--Renewables/corporates-usher-in-new-wave-of-u.s.-wind-and-solar-growth/).

[1052] *Id.* at 6 (citing Advanced Energy Economy, *Adding it All Up for Voluntary Buyers of Renewable Energy* (Jan. 2021), https://blog.advancedenergyunited.org/adding-

should include data from the Clean Energy Buyers Association Deal Tracker, and for utility commitments, transmission providers should include data from state resource plans and regulatory filings.[1053]

476. SREA and ACEG argue that the Commission should require transmission providers to incorporate utilities' generation planning announcements associated with net zero commitments and publicized utility resource plans, including SEC filings and public statements, into the development of Long-Term Scenarios.[1054] SREA contends that such a requirement would protect the interests of customers and generation developers because these announcements affect the marketplace.[1055] Breakthrough Energy suggests that utility targets and expected consumer demand should also be incorporated into the development of Long-Term Scenarios because actual demand is often higher than reflected in utility plans, which do not sufficiently incorporate corporate demand, including corporate buyer commitments.[1056]

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it-all-up-for-voluntary-buyers-of-renewable-energy; Microsoft, *Greener datacenters for a brighter future: Microsoft's commitment to renewable energy* (May 2016), ).

[1053] SEIA Initial Comments at 10 (citing Clean Energy Buyer Association, CEBA Deal Tracker, https://cebuyers.org/deal-tracker/; Sierra Club, *Check Out Where We Are Ready For 100%*, https://www.sierraclub.org/climate-and-energy/map).

[1054] ACEG Initial Comments at 28-29; SREA Initial Comments at 41-46.

[1055] SREA Initial Comments at 41-46.

[1056] Breakthrough Energy Initial Comments at 14-15.

477. LADWP, MISO, and NRECA support the inclusion of this category of factors as long as transmission providers are allowed to discount these factors in their analysis by assuming the goals or commitments may not be fully met.[1057] NRECA is concerned that factor category seven (utility and corporate commitments) carries a distinct risk of stranded transmission costs and therefore supports it being discounted.[1058] NRECA further states that it is concerned that stakeholders may try to use Long-Term Regional Transmission Planning to impose goals and commitments that lack the force of law.[1059] LADWP argues that the Commission should allow transmission planners to use discretion when identifying utility commitments and local goals.[1060] MISO is concerned about the inherent difficulty of modeling corporate commitments given the ambiguous nature of corporate footprints.[1061]

478. Several commenters oppose including utility and corporate commitments and/or federal, state, and local goals as a category of factors in Long-Term Scenarios.[1062] For

[1057] LADWP Initial Comments at 3; MISO Initial Comments at 36; NRECA Initial Comments at 32-33.

[1058] NRECA Initial Comments at 32 (citing GDS Assocs., Report, at 12 (Aug. 17, 2022)).

[1059] *Id.* at 32-33.

[1060] LADWP Initial Comments at 3.

[1061] MISO Initial Comments at 36.

[1062] Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Duke Initial Comments at 13; New York TOs Initial Comments at 11-12; Pennsylvania Commission Initial Comments at 6.

example, California Commission states that it is not clear what purpose would be served by requiring transmission providers to incorporate these commitments or goals into Long-Term Scenarios yet, at the same time, allowing them to discount such commitments or goals to account for their inherent uncertainty.[1063] New York TOs argue that corporate commitments are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider. Moreover, New York TOs state that, if a goal is not codified as a law, it is not clear that it is sufficiently solidified and supported to be included as a factor.[1064]

479. PJM argues that the NOPR proposal to include corporate commitments as a factor in Long-Term Scenarios is vague, inappropriate, and impractical, because even if PJM is able to develop a record of information in the expansive PJM footprint, this information will likely be incomplete. PJM argues that the burden to ensure that a transmission provider is aware of corporate commitments and goals should be on the corporation or another interested party.[1065]

480. Illinois Commission states that transmission planning criteria should not include vague terms such as "corporate goals," which could mean multiple things and may already be accounted for.[1066] Alabama Commission states that corporate commitments

[1063] California Commission Initial Comments at 20.

[1064] New York TOs Initial Comments at 11-12.

[1065] PJM Reply Comments at 37-38 (citing PJM Initial Comments at 68).

[1066] Illinois Commission Initial Comments at 7.

and goals are not a sufficient basis for planning decisions as they are not law and accountability for achieving them is limited.[1067] Similarly, Pennsylvania Commission states that determinants for Long-Term Scenarios should not be based on speculative factors, arguing that factors that include federal, state, and local laws and regulations that affect the future resource mix and demand are preferable to factors that include utility, corporate, federal, state, and local goals or policies that have no enforcement mechanisms.[1068] PPL states that utility and corporate commitments are unlikely to be sufficiently firm or definitive to pass state siting review.[1069]

**(2) Commission Determination**

481. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Seven into the development of Long-Term Scenarios because the relevant commitments and goals represent known consumer preferences that have been, and will continue to be, key drivers of Long-Term Transmission Needs. We agree with commenters that argue that corporate demand for clean energy resources, as

[1067] Alabama Commission Initial Comments at 6.

[1068] Pennsylvania Commission Initial Comments at 5-6.

[1069] PPL Initial Comments at 8.

demonstrated by the volume of bilateral corporate contracts with renewable energy resources, is already a major driver of changes in the resource mix and demand and that corporate and industrial customer demand for clean energy is projected to increase. We believe that it is necessary for transmission providers to incorporate publicly announced utility commitments in the development of Long-Term Scenarios. Such commitments may be ignored or overlooked in retail-level regulatory proceedings, but they nevertheless may have an impact on future changes in the resource mix and demand that must be accounted for to ensure the development of plausible Long-Term Scenarios.

482. We modify the NOPR proposal for Factor Category Seven to include federally-recognized Tribal goals that affect the resource mix and demand because we are persuaded by commenters that argue that such factors have the same potential to affect Long-Term Transmission Needs as federal, state, and local goals. We believe that federally-recognized Tribal goals should include publicly announced policy recommendations, such as energy vision reports.[1070] Further, as discussed under Additional Categories of Factors below, we recognize that energy equity and justice goals are potential factors within Factor Category Seven.

483. While federal, federally-recognized Tribal, state, and local goals may not have the same durability and binding impact of laws and regulations, we believe that it is appropriate for transmission providers to account for such goals in Long-Term Scenarios

[1070] *See, e.g.*, Columbia River Inter-Tribal Fish Comm'n, *Energy Vision for the Columbia River Basin* (Sept. 2022), https://critfc.org/wp-content/uploads/2022/09/CRITFC-Energy-Vision-Full-Report.pdf.

because these goals represent known preferences of governmental entities that affect Long-Term Transmission Needs. Such goals may improve or diminish the prospects of deploying certain technologies. For example, as AEE explains, local governments representing some of the most populous cities in the United States have established goals to have their cities' loads served by clean or renewable energy.[1071]

484. We disagree with commenters that argue that transmission providers should not be required to incorporate utility and corporate commitments into the development of Long-Term Scenarios because they may not be significant enough to drive Long-Term Transmission Needs or that accountability for achieving commitments and goals is too limited for these factors to be considered sufficiently firm.[1072] We acknowledge that utility and corporate commitments and governmental goals may be more likely to change over the transmission planning horizon than factors in other required factor categories; however, we are not persuaded that these commitments and goals are so speculative, amorphous, or unreliable that they should not be incorporated into Long-Term Scenarios at all. We emphasize that transmission providers have discretion, as discussed above, in how to account for these factors in the development of Long-Term Scenarios, and we

[1071] AEE Initial Comments at 10-11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets).

[1072] Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Illinois Commission Initial Comments at 7; New York TOs Initial Comments at 11-12; Pennsylvania Commission Initial Comments at 5-6; PJM Reply Comments at 37-38 (citing PJM Initial Comments at 68); PPL Initial Comments at 8.

note, as discussed in further detail below, that transmission providers can account for the uncertainty associated with the achievement of these commitments and goals by using discounting or putting more weight on the effects of these factors on Long-Term Transmission Needs in each of the required Long-Term Scenarios. Similarly, transmission providers have discretion to determine how to account for commitments and goals in Long-Term Scenarios if the effects of particular commitments or goals conflict with, negate, or duplicate the effects of other factors.

### (h) Additional Categories of Factors

#### (1) Comments on Energy Equity and Justice

485. Some commenters argue that the Commission should include equity and energy justice considerations in Long-Term Regional Transmission Planning.[1073] Grand Rapids NAACP, agreeing with NASEO, urges the Commission to expand factors considered in Long-Term Regional Transmission Planning to include energy equity and justice.[1074] Grand Rapids NAACP also states that transmission providers should be required to

[1073] *See, e.g.*, California Energy Commission Initial Comments at 2; City of New York Initial Comments at 9; Clean Energy Buyers Initial Comments at 8-9; Grand Rapids NAACP Initial Comments at 12, 15, 21, 23; Grand Rapids NAACP Reply Comments at 2-3, 5; Montclair Congregation Supplemental Comments at 1; NARUC Initial Comments at 3-4; NASEO Initial Comments at 5; PIOs Initial Comments at 35-36; PIOs Reply Comments at 15; Policy Integrity Initial Comments at 28; WE ACT Initial Comments at 4-6.

[1074] Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

follow federal, state, and local laws addressing the need for energy equity and justice.[1075] In concordance with PIOs, Grand Rapids NAACP urges the Commission to address equity in the transmission planning process because doing so would encourage competition and lower consumer costs.[1076] Finally, Grand Rapids NAACP urges the Commission to encourage transmission providers to develop metrics that advance economic equity and environmental justice by facilitating consideration of the impact of transmission infrastructure on disadvantaged communities.[1077]

486. US DOE asserts that energy justice considerations will form an integral part of transmission planning. Specifically, US DOE states that transmission planning can identify potential sources, sinks, and locations of transmission expansion facilities and that identifying locations where frontline communities and historically underserved communities have faced long-standing impacts may affect the future resource mix.[1078] NESCOE agrees with US DOE and argues that regional transmission planning processes should accommodate state efforts to advance equity and environmental justice concerns.[1079] New England for Offshore Wind argues that without a transparent and

[1075] *Id.*

[1076] *Id.* (citing PIOs Initial Comments at 35, 36).

[1077] *Id.* at 2-3 (citing NARUC Initial Comments at 3-4).

[1078] US DOE Initial Comments at 9.

[1079] NESCOE Reply Comments at 8-9.

inclusive transmission planning process, regional transmission planning efforts will be at odds with state policy on environmental justice.[1080]

487. PIOs state that the Commission should be clear that Long-Term Regional Transmission Planning complies with and incorporates relevant aspects of applicable federal, federally-recognized Tribal, state, and local environmental and energy justice policies—including future resource mix impacts, assignment of transmission benefits toward disadvantaged communities, and project selection.[1081]

488. CARE Coalition states that the Commission should consider issues of siting and the granting of permits that cause significant delays in construction of new transmission facilities.[1082] CARE Coalition emphasizes WE ACT's argument that a final rule should ensure that transmission planners and states "are cognizant about siting and the potential harms of transmission development to environmental justice communities."[1083] Relatedly, CARE Coalition highlights NRECA's argument that rural and poorer areas are

[1080] New England for Offshore Wind Initial Comments at 5.

[1081] PIOs Reply Comments at 15 (citing Grand Rapids NAACP Initial Comments at 12-15, 21-23 (listing notable federal, state, and local public policies requiring that equity and energy justice inform decision making processes); WE ACT Initial Comments at 6).

[1082] CARE Coalition Reply Comments at 3.

[1083] *Id.* at 4 (citing WE ACT Initial Comments at 6).

disproportionately burdened under the current regime because "siting decisions are primarily driven by technical and economic factors."[1084]

#### (2) Comments on Efficiency and Technology

489. NASEO argues that the Commission should expand its list of factors that transmission providers should include in Long-Term Regional Transmission Planning and Long-Term Scenarios to include increased energy efficiency of existing transmission lines, and the efficient use of existing rights of way.[1085] Invenergy suggests that the Commission expressly require consideration of advanced-stage merchant HVDC transmission as a factor in regional transmission planning scenarios.[1086] Invenergy highlights US DOE's proposal that transmission providers consider trends in the development of HVDC network technology, arguing, however, that such consideration should include incorporating and accounting for HVDC transmission facilities in transmission planning models and scenarios.[1087]

#### (3) Comments Regarding Enhanced Reliability and Interregional Transfer Capability

490. PJM recommends that the Commission require enhanced reliability and Interregional Transfer Capability as two additional categories of factors that transmission

[1084] *Id.* (citing NRECA Initial Comments at 39 n.111).

[1085] NASEO Initial Comments at 5.

[1086] Invenergy Initial Comments at 6-7.

[1087] Invenergy Reply Comments at 11 (citing US DOE Initial Comments at 13).

providers must incorporate into the development of Long-Term Scenarios.[1088] PJM envisions enhanced reliability to include, but not be limited to, storm hardening of critical facilities, reducing the number of critical CIP-014 facilities through transmission upgrades, coordination of infrastructure development with natural gas pipelines serving generation in the region, and ensuring redundancy of facilities, where appropriate, to address the threat of physical or cyber attacks.[1089] PJM envisions Interregional Transfer Capability to be established in accordance with the methodology that the Commission adopts in a subsequent order.[1090]

491. Invenergy agrees with the additional categories of factors that PJM proposes.[1091] ELCON supports the consideration of transfer capability between seams, which it asserts would provide transmission providers with the ability to develop and consider solutions that may solve for multiple drivers and offer greater benefits to more consumers.[1092] In contrast, AEE states that it disagrees with the additional categories of factors that PJM proposes, although it agrees with PJM that enhanced reliability planning is an important consideration.[1093]

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[1088] PJM Initial Comments at 6, 13, 65-67.

[1089] *Id.* at 66.

[1090] *Id.* at 66-67.

[1091] Invenergy Reply Comments at 11.

[1092] ELCON Initial Comments at 8.

[1093] AEE Reply Comments at 20.

**(4) Commission Determination**

492. We recognize that some commenters ask the Commission to require transmission providers to incorporate several categories of factors in addition to those proposed in the NOPR in the development of Long-Term Scenarios. We decline to include energy equity and justice as a distinct and additional category of factors because we believe that these important energy equity and justice laws and regulations, or goals, that are likely to affect Long-Term Transmission Needs, are accounted for in Factor Category One: federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, or Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[1094] Stakeholders will have a meaningful opportunity to identify any such factors as part of the open and transparent stakeholder process described below in the Stakeholder Process and Transparency section.

493. We decline to adopt Invenergy's recommendation that the Commission require transmission providers to include advanced-stage merchant HVDC transmission as an additional category of factors. The Commission did not propose specific requirements in the NOPR regarding merchant HVDC transmission facilities under development, and we are not persuaded by the evidence in the record that the Commission should include advanced-stage HVDC transmission facilities in the minimum set of known determinants

[1094] Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

of Long-Term Transmission Needs. We reiterate that transmission providers may be aware of additional categories of factors beyond those adopted in this final rule that drive Long-Term Transmission Needs and may incorporate additional categories of factors in the development of Long-Term Scenarios provided that each Long-Term Scenario remains plausible.

494. In response to PJM's request for the Commission to require enhanced reliability and Interregional Transfer Capability[1095] as additional categories of factors,[1096] we find that the record in this proceeding is insufficient to adequately consider whether to require transmission providers to adopt such categories of factors in this final rule. As noted in our response to Invenergy just above, transmission providers may incorporate additional categories of factors in the development of Long-Term Scenarios provided that each Long-Term Scenario remains plausible. We note that, in this final rule, we provide transmission providers with flexibility in how they develop Long-Term Scenarios to identify Long-Term Transmission Needs. We believe that other parts of this final rule enable transmission providers to account for enhanced reliability and Interregional

[1095] We define Interregional Transfer Capability for purposes of this final rule consistent with the definition of total transfer capability in the Commission's regulations as: "the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards." 18 CFR 37.6(b)(1)(vi). In the context of Interregional Transfer Capability, an "area" in the above definition would be a transmission planning region composed of transmission providers.

[1096] PJM Initial Comments at 6, 13, 65-67.

Transfer Capability by modeling sensitivities and using certain transmission benefits. As discussed below, we require transmission providers to develop at least one sensitivity analysis, applied to each Long-Term Scenario, to account for uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area that determine the benefits of or need for Long-Term Regional Transmission Facilities. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to measure, and consider as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide.

### c. Treatment of Specific Categories of Factors

#### i. NOPR Proposal

495. The Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning incorporate and be consistent with federal, state, and local laws and regulations that affect the future resource mix and demand; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load-serving entities. The Commission preliminarily found that it is reasonable to require transmission providers to assume that legally binding obligations and state utility regulator-approved plans will be followed and that expected supply obligations for load-serving entities will be fully met. As a result, the Commission explained that, under the proposal, transmission providers cannot discount

the factors included in the categories of federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load-serving entities.[1097]

496. In addition, the Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning include trends in technology and fuel costs within and outside the electricity supply industry, including shifts toward electrification of buildings and transportation; resource retirements; and generator interconnection requests and withdrawals. For these particular categories of factors, the Commission proposed to provide transmission providers with flexibility in how they incorporate each factor into Long-Term Scenarios as long as transmission providers identify and publish specific factors for each of these categories, as further described below.[1098]

497. Further, the Commission proposed to require that each Long-Term Scenario incorporate utility and corporate goals and federal, state, and local goals that affect the future resource mix and demand. However, the Commission acknowledged that these categories of factors are less binding and more likely to change over time, and therefore their impact on the future resource mix and demand are less certain, than other categories of factors. For this reason, the Commission preliminarily found that it may be

[1097] NOPR, 179 FERC ¶ 61,028 at P 106.

[1098] *Id.* P 107.

appropriate for transmission providers to discount such goals to account for this uncertainty. The Commission explained that transmission providers would not be required to assume that utility and corporate goals and federal, state, and local goals that affect the future resource mix will be fully met.[1099]

**ii. Comments**

498. Several commenters, that generally support the NOPR proposal, support discounting and rebut arguments opposing discounting.[1100] NRECA, Exelon, and TAPS argue that the NOPR proposal to allow transmission providers to discount some categories of factors while weighing factors in other categories more heavily strikes an appropriate balance.[1101] Specifically, Exelon supports the NOPR proposal to allow for variation in the treatment of different categories of factors such as legislated energy policy, which it states should not vary by scenario, and non-binding targets, which it states may be discounted yet are important to consider.[1102] TAPS also supports the proposed flexibility in how transmission providers incorporate factors that are not federal,

[1099] *Id.* P 108.

[1100] Exelon Initial Comments at 10-11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7; NRECA Initial Comments at 32; TAPS Initial Comments at 2-3, 8.

[1101] Exelon Initial Comments at 10-11; NRECA Initial Comments at 32; TAPS Initial Comments at 2-3, 8.

[1102] Exelon Initial Comments at 10-11.

state, and local laws and regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities.[1103]

499. Some commenters express concerns that the NOPR proposal would allow transmission providers in each transmission planning region to discount, or not fully incorporate, some factors when developing Long-Term Scenarios.[1104] Clean Energy Associations state that certain factors (i.e., federal, state, and local policies, utility integrated resource plans, generator retirements, interconnection requests, corporate commitments, and trends in technology and fuel costs) can be quantified and should be reflected in Long-Term Scenarios without discounting.[1105] Clean Energy Buyers are concerned that the flexibility proposed in the NOPR for transmission providers to incorporate into their Long-Term Scenarios the categories of factors that include trends in fuel costs and technologies both inside and outside the electricity supply industry, including regarding shifts in electrification of transport and buildings, resource retirements, and generator interconnection requests and withdrawals, could delay the transmission build-out.[1106] ACEG recommends that the Commission presume that all factors are required to be incorporated (and not discounted or only considered) unless the

[1103] TAPS Initial Comments at 2-3, 8.

[1104] ACEG Initial Comments at 27-28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10-11; Pine Gate Initial Comments at 23-25; PIOs Initial Comments at 18-19; SEIA Initial Comments at 8-10.

[1105] Clean Energy Associations Initial Comments at 10-11.

[1106] Clean Energy Buyers Initial Comments at 15-16.

Commission approves a request from the transmission providers in a transmission planning region not to include a factor.[1107] In response, California Municipal Utilities argue that mandating the use of specific factors would not account for the cost consequences of such mandates, which must be considered for any transmission planning requirements to be just and reasonable.[1108]

500. Several commenters object to the Commission's proposal to provide transmission providers with the flexibility to discount utility and corporate and federal, state, and local goals that affect the future resource mix and demand.[1109] Amazon states that transmission providers should not be allowed to discount clean energy goals in their development of Long-Term Scenarios without proving such discounting is just and reasonable by showing evidence that such goals have been unfulfilled in the past, or that those goals have been altered or abandoned.[1110]

501. PIOs state that the NOPR proposal to discount Factor Category Seven would allow transmission providers to game the results if their incentives are contrary to consumers' goals.[1111] SEIA urges the Commission to limit the flexibility given to transmission

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[1107] ACEG Initial Comments at 27.

[1108] California Municipal Utilities Reply Comments at 5-6.

[1109] Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10-11; Pine Gate Initial Comments at 24-25; PIOs Initial Comments at 18-19; SEIA Initial Comments at 8.

[1110] Amazon Initial Comments at 4.

[1111] PIOs Initial Comments at 18-19.

providers regarding this factor because SEIA believes that they would ignore certain factors if consideration is not mandatory.[1112] Further, Clean Energy Associations argue that utility, corporate, and federal, state, and local goals should be fully incorporated, without discounting targets not enshrined in law or regulation. If necessary, Clean Energy Associations contend, changes in non-binding obligations could be treated as a sensitivity or probabilistic change in one or more scenarios to determine how they might affect transmission development.[1113]

502. PIOs state that, when utilities make commitments affecting the future resource mix and consumer demand, they should be held to them and that granting transmission providers complete discretion to discount such factors could undermine the goals of the NOPR proposal. Thus, PIOs state, the Commission should set minimum requirements for some factors, including for incorporating corporate commitments into future resource mix estimates.[1114] PIOs assert that widespread support exists for these recommendations, citing ELCON as an example.[1115]

[1112] SEIA Initial Comments at 8.

[1113] Clean Energy Associations Initial Comments at 10-11.

[1114] PIOs Initial Comments at 17-18.

[1115] PIOs Reply Comments at 10-11 (citing ELCON Initial Comments at 4).

503. Pine Gate argues that transmission providers should be required to assume that utility and corporate and federal, state, and local goals that affect the future resource mix will be fully met in at least one of their Long-Term Scenarios.[1116]

504. In addition, Pattern Energy argues that the Commission should distinguish between generation assumptions and demand assumptions for purposes of 20-year transmission planning so that there is no ambiguity. For example, Pattern Energy states that transmission providers should not be permitted to utilize their planning for load growth to satisfy the requirement to plan for changing resources and demand. Pattern Energy asserts that transmission providers should be required to distinguish between modeling a changing resource mix and, separately, a changing demand profile, arguing that both are important and should be considerations in near-term and long-term transmission planning.[1117]

505. NYISO argues that the final rule should permit transmission providers to appropriately account for, in coordination with state and local entities and stakeholders, the likely effect of applicable laws and regulations on the need for transmission and to realistically appraise achievement of such laws and regulations.[1118]

506. Some commenters oppose the NOPR proposal to require that transmission providers incorporate applicable local laws and regulations in their development of Long-

[1116] Pine Gate Initial Comments at 25.

[1117] Pattern Energy Initial Comments at 26.

[1118] NYISO Initial Comments at 23.

Term Scenarios.[1119] Duke explains that although local laws and regulations for decarbonization and electrification may affect the resource mix and demand at the local level, it is unclear how such laws would have a material effect on regional transmission planning that warrants the additional burden of tracking and incorporating them into Long-Term Scenarios.[1120] Alabama Commission argues that local laws, regulations, and goals might change or conflict with the policy perspectives of other states.[1121] PPL claims that the NOPR proposal is impractical and will significantly increase uncertainty, which in turn will invite disagreement and litigation.[1122] PJM recommends that the Commission require transmission providers to only consider local laws, local regulations, and local goals to the extent that such laws, regulations, and goals are brought to their attention by states, other local regulators, or stakeholders.[1123]

[1119] Alabama Commission Initial Comments at 5-6; Ameren Initial Comments at 9-10; Duke Initial Comments at 13-14, 16; ISO-NE Initial Comments at 26-27; ISO/RTO Council Initial Comments at 4-5; NYISO Initial Comments at 21-23.

[1120] Duke Initial Comments at 13.

[1121] Alabama Commission Initial Comments at 5-6.

[1122] PPL Initial Comments at 7-8.

[1123] PJM Reply Comments at 38 (citing PJM Initial Comments at 68).

### iii. Commission Determination

#### (a) Treatment of Factors in the First Three Categories

507. With regard to the first three categories of factors,[1124] we require transmission providers in each transmission planning region to assume that legally binding obligations (i.e., federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met. Therefore, we require that each Long-Term Scenario account for and be consistent with, and not discount, factors in the first three categories of factors once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs. We believe it is necessary to prohibit discounting of factors in the first three categories of factors because they are more certain drivers of Long-Term Transmission Needs, relative to factors in other factor categories.

508. We clarify that transmission providers may rely on the open and transparent stakeholder process discussed below to identify the factors in the first three required categories of factors. More specifically, this final rule does not obligate transmission providers to independently identify all of the factors in the first three categories of

[1124] As explained above, the first three categories of factors are: (1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; and (3) state-approved integrated resource plans and expected supply obligations for load-serving entities.

factors. We believe that it would be unduly burdensome and potentially impractical for transmission providers to independently identify all of the potential factors in the first three categories of factors, which will include numerous federal, federally-recognized Tribal, state, and local laws and regulations, as well as integrated resource plans and expected supply obligations for load-serving entities.[1125] However, transmission providers may, if they choose, independently identify factors in the first three categories of factors as part of the stakeholder process, discussed further in the Stakeholder Process and Transparency section below.

509. We believe that this clarification addresses PJM's request that we clarify that the burden of making the transmission provider aware of laws, regulations, and goals rests with stakeholders and not with the transmission provider itself.[1126] We also believe that this clarification mitigates the potential administrative burdens and compliance risks identified by ISO-NE, as well as the burden of incorporating factors identified by SPP.[1127]

[1125] The Commission has previously found that transmission providers "cannot later be faulted" for failing to consider projections of a need for service from a point-to-point transmission customer if such projections are not provided by the transmission customer. Order No. 890, 118 FERC ¶ 61,119 at P 487; *id.* ("We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. . . . If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests.").

[1126] PJM Initial Comments at 68.

[1127] ISO-NE Initial Comments at 26-27; SPP Initial Comments at 7-8.

510. In addition, as clarified above, transmission providers retain the discretion to determine whether particular factors, including those in the first three categories of factors, that stakeholders identify are likely to affect Long-Term Transmission Needs. Thus, transmission providers may determine, for example, that some stakeholder-identified local laws and regulations that fall within Factor Categories One and Two are unlikely to affect Long-Term Transmission Needs and therefore need not be accounted for in the development of Long-Term Scenarios. We believe that this clarification addresses concerns about the additional burden some commenters identified of tracking and incorporating local laws and regulations into the development of Long-Term Scenarios, as well as concerns that the inclusion of local laws and regulations in the first two categories of factors creates a burden for transmission providers to account for factors that are unlikely to affect Long-Term Transmission Needs.[1128]

511. We believe that the open and transparent stakeholder process discussed below in the Stakeholder Process and Transparency section will help transmission providers to ensure that each Long-Term Scenario accounts for factors in the first three categories of factors without discounting the effects of those factors on Long-Term Transmission Needs. We expect that transmission providers will rely, at least in part, on information that relevant federal, state, and local government entities, federally-recognized Tribes, utilities, and load-serving entities provide during the required open and transparent stakeholder process to determine if specific factors are likely to affect Long-Term

[1128] Duke Initial Comments at 13.

Transmission Needs and how to account for those specific factors in Long-Term Scenarios. We agree with NYISO regarding the value of coordination and clarify that transmission providers may work in coordination with government entities and stakeholders to determine how applicable laws and regulations may affect Long-Term Transmission Needs.[1129]

512. We recognize that some commenters raise concerns as to whether factors in the first three categories of factors can be fully achieved (e.g., a legislative requirement is met) or may have various levels of impact on Long-Term Transmission Needs.[1130] At the outset, we find it appropriate to assume legally binding obligations are met, unless and until there is a change in law. Government entities have an interest and ability to ensure that the requirements of laws and regulations are fully achieved. Similarly, utilities and load-serving entities, as well as the relevant retail regulator, have an interest in developing accurate integrated resource plans and expected supply obligations that can be fully achieved. Even in the limited circumstances in which these factors are not fully achieved, we expect the targets or requirements associated with these factors will be informative for purposes of identifying Long-Term Transmission Needs. We acknowledge that, for certain factors, there may be insufficient information for transmission providers to determine, or stakeholder disagreement about, how the factor will affect Long-Term Transmission Needs. In such instances, we clarify that

[1129] NYISO Initial Comments at 23.

[1130] *Id.*

transmission providers have discretion over how to account for a factor in the first three categories of factors in their Long-Term Scenarios as long as the assumptions in each Long-Term Scenario are consistent with legally binding obligations, state-approved integrated resource plans, and expected supply obligations of load-serving entities.

513. For example, when a legally binding obligation sets a minimum requirement or threshold (e.g., a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030), transmission providers may develop Long-Term Scenarios assuming either the minimum amount of the requirement or more than the minimum amount of the requirement (e.g., modeling 10 gigawatts of electric storage resources deployed by 2030 instead of the minimum 5 gigawatts) but may not develop any Long-Term Scenarios that are inconsistent with that minimum (e.g., modeling only 2 gigawatts of electric storage resources deployed by 2030). We believe that these clarifications sufficiently address PPL's concerns regarding the uncertainty associated with how transmission providers are expected to translate factors, including local laws and regulations, into Long-Term Scenarios.[1131] We note that the requirement, discussed further below, that Long-Term Scenarios be plausible and diverse also clarifies how transmission providers must account for factors in the Long-Term Scenarios. That is, while transmission providers can model assumptions that exceed the minimum requirements of factors in the first three categories in developing Long-Term Scenarios, they can only exceed those minimum requirements such that each Long-Term Scenario

[1131] PPL Initial Comments at 8.

remains plausible.[1132] Similarly, the requirement that Long-Term Scenarios be diverse ensures that transmission providers will model the effect of factors on Long Term Transmission Needs in different ways, and thus that Long-Term Scenarios help to manage uncertainty over how factors will affect Long-Term Transmission Needs.

514. We disagree with ISO-NE's claim that requiring that each Long-Term Scenario account for and consistently reflect the first three categories of factors would unnecessarily prevent testing of variations with these categories of factors. Where a factor's effect is not clear on its face, transmission providers have discretion, within reason, to determine the likely effect of full achievement of the factor and reflect that into development of the Long-Term Scenarios. Transmission providers also are not limited to assuming only the minimum requirements of a factor are fully achieved in developing the Long-Term Scenarios.

515. We also are unpersuaded by commenter claims that local laws and regulations might conflict with state laws and regulations and, therefore, we should not include local laws and regulations in the first two categories of factors.[1133] However, we acknowledge that there may be limited circumstances when two legally binding factors have conflicting or opposite implications for Long-Term Transmission Needs. We clarify that,

[1132] Likewise, as discussed in the Treatment of Factors in the Last Four Categories section, transmission providers may only discount the effect of factors in the last four categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

[1133] Alabama Commission Initial Comments at 5-6; PJM Initial Comments at 68.

in such circumstances, transmission providers shall reconcile this information while giving full effect to the maximum extent possible to all legally binding factors. For example, where two laws have equal and opposite effect, transmission providers may need to incorporate them as negating each other, as necessary to comply with the requirement to produce plausible Long-Term Scenarios. In circumstances when that is not possible because the legally binding factors support alternatives to the same assumption used to develop Long-Term Scenarios, transmission providers could use two or more of the three required Long-Term Scenarios, or develop additional Long-Term Scenarios, to capture the differences implied by each of the conflicting factors.

### (b) Treatment of Factors in the Last Four Categories

516. We affirm that transmission providers have additional discretion in how they account for each factor in the last four categories of factors compared to how they account for each factor in the first three categories.[1134] After transmission providers have determined that a specific factor, stakeholder-identified or otherwise, is likely to affect Long-Term Transmission Needs over the transmission planning horizon, transmission providers must then assess the extent to which the anticipated effects on Long-Term Transmission Needs due to that factor are likely to be realized in full, in part, or

[1134] As explained above, the last four categories of factors are: (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.

exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. For example, for a corporate commitment identified in Factor Category Seven, transmission providers can make a determination that only a fraction of that corporate commitment will actually be met, and the transmission providers can subsequently model more limited effects on Long-Term Transmission Needs due to that factor, in some or all Long-Term Scenarios. Likewise, transmission providers may put more weight on the factor by modeling more than the projected change in some or all Long-Term Scenarios to reflect the transmission providers' view regarding the likelihood that the anticipated effects on Long-Term Transmission Needs due to that factor will occur. Transmission providers may choose to discount or put more weight on the effects on Long-Term Transmission Needs due to factors in Factor Categories Four through Seven to account for uncertainty when developing plausible and diverse Long-Term Scenarios.

517. Several commenters generally support this flexibility to treat the last four categories of factors differently from the first three.[1135] We believe that requiring transmission providers to incorporate the last four categories of factors, but allowing transmission providers to discount the effects of factors within these categories, strikes an appropriate balance between requiring factors in these categories be given full weight, and allowing them to be excluded entirely in developing Long-Term Scenarios. We

[1135] APPA Initial Comments at 27-28; Exelon Initial Comments at 10-11 (citing NOPR, 179 FERC ¶ 61,028 at P 121); NRECA Initial Comments at 29-32; TAPS Initial Comments at 2-3, 8.

believe that these categories of factors affect Long-Term Transmission Needs, and absent a requirement to incorporate them, transmission providers may fail to identify, evaluate, and select more efficient or cost-effective Long-Term Regional Transmission Facilities to address those Long-Term Transmission Needs. On the other hand, these categories of factors are less certain than the first three categories and should not necessarily be given the same weight in developing Long-Term Scenarios as factors that are legally binding.

518. We disagree with the concern that this flexibility could allow transmission providers to ignore the last four factor categories[1136] because the final rule requires transmission providers to incorporate all categories of factors in each Long-Term Scenario, even if they discount specific factors within the category, and requires that all Long-Term Scenarios be plausible.[1137] We reiterate that transmission providers may only discount the effects of factors in these categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

### d. Stakeholder Process and Transparency

#### i. NOPR Proposal

519. The Commission proposed to require that transmission providers identify and publish on an Open Access Same-Time Information System (OASIS) or other public

[1136] *E.g.*, ACEG Initial Comments at 27-28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10-11; Pine Gate Initial Comments at 23-25; PIOs Initial Comments at 18-19; SEIA Initial Comments at 8-10.

[1137] ACEG Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 11.

website a list of the factors that fall into each of the required categories of factors that they will incorporate in their development of Long-Term Scenarios. The Commission explained that transmission providers would be responsible for identifying all the factors they know of and are considering incorporating in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission also proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors that transmission providers must incorporate in their development of Long-Term Scenarios, such as specific laws, regulations, goals, and commitments, and to provide input on how to appropriately discount factors that are less certain.[1138]

520. The Commission noted that, under Order No. 1000, transmission providers must already have procedures in their OATTs that give stakeholders a meaningful opportunity to submit proposed transmission needs driven by Public Policy Requirements and that allow transmission providers to identify, out of the larger set of potential transmission needs driven by Public Policy Requirements that stakeholders propose, those needs for which transmission facilities will be evaluated.[1139] Therefore, the Commission explained that transmission providers may be able to modify and expand these existing procedures

[1138] NOPR, 179 FERC ¶ 61,028 at P 109.

[1139] *Id.* P 110 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 206-207; Order No. 1000-A, 139 FERC ¶ 61,132 at P 335).

for identifying transmission needs driven by Public Policy Requirements to meet these proposed requirements regarding the identification of factors for incorporation into Long-Term Scenarios.[1140]

### ii. Comments

#### (a) State Input

521. Several commenters emphasize the important role of stakeholders, including states, in identifying or commenting on the factors to be included in the development of Long-Term Scenarios.[1141] In addition, Southeast PIOs note that states do not currently engage in regional transmission planning processes to any meaningful degree, and therefore, the Commission should encourage their participation in shaping and conducting Long-Term Regional Transmission Planning.[1142]

522. Some commenters discuss the important role of states in identifying factors within specific category of factors.[1143] DC and MD Offices of People's Counsel assert that the final rule should explicitly require information on the factors to be provided by appropriate authorities, such as state agencies.[1144] New Jersey Commission supports the

[1140] *Id.*

[1141] APPA Initial Comments at 27-29; PIOs Initial Comments at 22; PJM Initial Comments at 70; Southeast PIOs Initial Comments at 45, 46-47.

[1142] Southeast PIOs Initial Comments at 45-46; State Officials Supplemental Comments at 1.

[1143] DC and MD Offices of People's Counsel Initial Comments at 12; New Jersey Commission Initial Comments at 14-15.

[1144] DC and MD Offices of People's Counsel Initial Comments at 12.

Commission's proposal to require that states have a meaningful opportunity to propose potential factors to be incorporated into the development of Long-Term Scenarios and to provide input on appropriately discounting less certain factors.[1145] NESCOE asserts that, if states do not play a central role in determining the factors, the proposed reforms will likely run into the problem that underlies the Order No. 1000 public policy transmission planning process in New England, where states do not have a decision-making role over project selection even though state laws or policies could be the driver for the project.[1146]

523. However, other commenters state that their existing processes are adequate for determining the relevant factors to include in Long-Term Regional Transmission Planning.[1147] PJM states that it currently has processes and standing committees that allow states and stakeholders to participate in discussions of factors to use in its transmission planning processes. For example, PJM asserts that its Independent State Agencies Committee is set up to receive feedback on transmission planning from states, and it discusses, among other things, assumptions used in the models, relevant regulatory initiatives and their impact, and alternative sensitivities, as well as what was discussed at other committee meetings. In addition, PJM states, it vets all proposed transmission

[1145] New Jersey Commission Initial Comments at 14-15.

[1146] NESCOE Initial Comments at 28-29.

[1147] MISO Initial Comments at 34-35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6; PJM Initial Comments at 6, 64, 70-71.

solutions with its Transmission Expansion Advisory Committee before submitting them to the PJM board for approval.[1148]

**(b) Transparency, Enforcement, and Accuracy**

524. Cross Sector Representatives state that Long-Term Regional Transmission Planning processes should provide transparency for impacted stakeholders.[1149] SEIA argues that the Commission should adopt clear, uniform language that sets forth the specific goals and deliverables from the proposed Long-Term Regional Transmission Planning process for transmission providers to include in their tariffs, including language that mirrors the proposed list of categories of factors the Commission included in the NOPR.[1150]

525. Several commenters support the NOPR proposal to require transmission providers to post the list of factors that they will incorporate into their Long-Term Scenarios on a public website for stakeholder comment.[1151] Pine Gate recommends that the Commission further require that transmission providers identify and publish all factors that were considered but not incorporated.[1152]

[1148] PJM Initial Comments at 70-71.

[1149] Cross Sector Representatives Supplemental Comments at 1.

[1150] SEIA Reply Comments at 3-4 (citing PJM Initial Comments at 27-28).

[1151] Ameren Initial Comments at 11-12; APPA Initial Comments at 28; NESCOE Initial Comments at 28; Pine Gate Initial Comments at 25; PIOs Initial Comments at 22.

[1152] Pine Gate Initial Comments at 25.

526. Clean Energy Buyers state that, to ensure transparency and just and reasonable rates, the Commission should require that transmission providers post the details regarding any proposed or adopted discounting of factors on OASIS, including: (1) which factors are to be discounted; (2) the extent of the discounting; and (3) the justification for and derivation of the amount of discounting deemed appropriate.[1153]

527. GridLab and R Street propose modifications to the NOPR proposal regarding the role of stakeholders.[1154] GridLab proposes that state agencies, other stakeholders, and independent experts could play a dominant role in enforcing the Commission's requirement to incorporate specific categories of factors, and that the Commission would provide a common framework establishing guidelines on the kinds of factors that transmission providers should consider, at a minimum, in developing Long-Term Scenarios.[1155] In addition, R Street argues that governance mechanisms should drive the selection of data sets, methods, and assumptions behind these factors to promote objective accuracy.[1156]

### iii. Commission Determination

528. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission

[1153] Clean Energy Buyers Initial Comments at 16-17.

[1154] GridLab Initial Comments at 20-21; R Street Initial Comments at 7.

[1155] GridLab Initial Comments at 21.

[1156] R Street Initial Comments at 7.

planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios.[1157] As discussed below, we also adopt the NOPR proposal, with modification, to require transmission providers to publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of those factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.

529. We believe that a robust stakeholder process will ensure that transmission providers can identify which, and how, specific factors might influence Long-Term Transmission Needs over the transmission planning horizon. For this reason, consistent with Order No. 890's transmission planning principles,[1158] we require transmission

[1157] As an example, transmission providers would provide stakeholders with an opportunity to describe how a specific state law in the first category of factors will result in the development of new resources of a certain type, the retirement of existing resources, or changes in demand patterns due to increased electrification.

[1158] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 454.

providers to give stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate in Long-Term Scenarios, including how to account for a specific factor in terms of how the factor may affect Long-Term Transmission Needs. We clarify that this meaningful opportunity for stakeholders to provide timely input includes the opportunity to propose factors, provide information and identify sources of best available data, propose how a factor may affect Long-Term Transmission Needs, and explain how that factor could be reflected in the development of Long-Term Scenarios, including the extent to which it is appropriate to discount the effects of certain factors on Long-Term Transmission Needs. We note that some transmission providers have existing processes in place that allow states and stakeholders to participate in discussions of factors, which transmission providers can propose, with any necessary modifications, to comply with this final rule.[1159]

530. We believe that affording stakeholders a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios will help transmission providers to develop more accurate assumptions to serve as the basis for their Long-Term Scenarios. Specifically, with stakeholder input, transmission providers will be in a better position to determine which specific factors within each category of factors they should account for in the development of Long-Term Scenarios, as well as how best to incorporate them. Stakeholder input is particularly important for factors in the first three categories of

[1159] MISO Initial Comments at 34-35; PJM Initial Comments at 6, 64, 70-71.

factors because federal, state, and local government entities, federally-recognized Tribes, and utilities, load-serving entities, and their retail regulators that participate in the stakeholder process are distinctly positioned to provide transmission providers with vital information on how the factors over which they have authority or govern are likely to influence Long-Term Transmission Needs over the transmission planning horizon. Similarly, utilities, corporations, and governments that participate in the stakeholder process are distinctly positioned to provide transmission providers with vital information regarding factors in Factor Category Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs. The required stakeholder process ensures that all stakeholders, including states, can provide important and useful information concerning factors that they believe will affect Long-Term Transmission Needs.

531. We recognize that different stakeholders may provide information about the same factor that is contradictory – an issue identified by some commenters.[1160] Different stakeholders may also provide different analyses showing, for example, how a specific factor will affect resource additions and retirements. However, as we explain earlier, transmission providers have discretion regarding how to account for specific factors in their development of Long-Term Scenarios. In reviewing the information provided by stakeholders in the open and transparent stakeholder process, transmission providers may

[1160] *E.g.*, Undersigned States Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 106).

weigh more heavily one source of information over another. To maintain transparency for stakeholders, transmission providers must include a general statement explaining how they will account for each factor in their Long-Term Scenarios on the public portion of an OASIS or other public website, as further described below.

532. We also believe that the information provided in the open and transparent stakeholder process will reduce the burden placed on transmission providers to identify and assess the impact of relevant factors for each category. For example, transmission providers can rely on the open and transparent stakeholder process to identify the multiple relevant local laws and regulations that are likely to influence Long-Term Transmission Needs over the transmission planning horizon. The same is true for the utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs in Factor Category Seven. During the stakeholder process, government entities, utilities, and corporate entities can identify their publicly announced goals and provide feedback on how the transmission providers can account for these publicly announced goals in Long-Term Scenarios. These entities will have an opportunity to provide information to help the transmission providers determine the likelihood that they will achieve their stated goals, which the transmission providers can then use to discount the specific factors in Factor Category Seven, if necessary.

533. With regard to the information about factors and categories of factors that transmission providers must publish on the public portion of an OASIS or other public website, we modify the proposal in the NOPR. We require transmission providers to

publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of these factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.[1161] Transmission providers must post this information after stakeholders, including states, have had the meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.

534. We believe that this transparency is necessary to make clear to stakeholders which specific factors transmission providers incorporate into Long-Term Scenarios and how they incorporate those factors. We believe the posting requirement will also provide greater transparency into how transmission providers develop Long-Term Scenarios (discussed below), as some commenters requested, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors.

[1161] As discussed above, transmission providers may not discount factors in Factor Categories One through Three.

535. In response to commenters requesting additional transparency,[1162] we require transmission providers to publish on the public portion of an OASIS or other public website the factors that were considered but not accounted for in the development of Long-Term Scenarios. We believe this requirement will help stakeholders understand which factors, either identified in the stakeholder process or independently identified by a transmission provider, the transmission providers in a transmission planning region have determined are unlikely to affect Long-Term Transmission Needs. This transparency also ensures that stakeholder-proposed factors are reviewed in a fair and non-discriminatory manner.

536. We decline to require transmission providers to publicly publish the justification for and derivation of the amount of discounting deemed appropriate, as requested by Clean Energy Buyers.[1163] We believe such a requirement to detail the rationale for the treatment of each factor in Factor Categories Four through Seven, across all Long-Term Scenarios, would create a time-consuming administrative burden for transmission providers that is not justified by the value of the additional information provided to stakeholders.

537. We decline to adopt modifications to the NOPR proposal that would diminish the role of the transmission providers in developing Long-Term Scenarios.[1164] Transmission

[1162] *E.g.*, Pine Gate Initial Comments at 25.

[1163] Clean Energy Buyers Initial Comments at 16-17.

[1164] *E.g.*, GridLab Initial Comments at 20-21; R Street Initial Comments at 7.

providers must provide stakeholders with a meaningful opportunity to propose potential factors and to provide input on how to incorporate specific factors in the development of Long-Term Scenarios, as described above. However, we reiterate that transmission providers are not required to incorporate stakeholder-identified factors into their development of Long-Term Scenarios merely because stakeholders propose them, if transmission providers determine that the factor is unlikely to influence Long-Term Transmission Needs over the transmission planning horizon. Consistent with Order No. 890, the ultimate responsibility for transmission planning remains with the transmission provider.[1165]

### 4. Number and Development of Long-Term Scenarios

#### a. NOPR Proposal

538. In the NOPR, the Commission proposed to require transmission providers to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning at least once during a transmission planning cycle.[1166] The Commission explained that it preliminarily found that using at least four distinct Long-

[1165] Order No. 890, 118 FERC ¶ 61,119 at P 454 ("In response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarify that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in this Final Rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.").

[1166] NOPR, 179 FERC ¶ 61,028 at PP 121-126.

Term Scenarios is a reasonable lower bound for the number of Long-Term Scenarios that transmission providers must evaluate in Long-Term Regional Transmission Planning. The Commission explained that this minimum number of Long-Term Scenarios would help to ensure that transmission providers conduct Long-Term Regional Transmission Planning that identifies more efficient or cost-effective regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand. The Commission explained that to satisfy this requirement, transmission providers could develop a base case and three alternatives, or a low-, medium-, and high-level assumption for the factors that transmission providers (and their stakeholders) believe to be important to conduct Long-Term Regional Transmission Planning to more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand, along with a scenario that accounts for a high-impact, low-frequency event (as discussed below).[1167]

539. Consistent with the Order No. 890 transparency transmission planning principle,[1168] the Commission proposed to require transmission providers in each

[1167] *Id.* P 122.

[1168] The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs they use to create each Long-Term Scenario. The Commission explained that this transparency requirement will allow stakeholders to understand how each scenario differs.

540. Similarly, consistent with the coordination transmission planning principle established in Order No. 890,[1169] the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input into the identification of which Long-Term Scenarios are developed. The Commission proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. Furthermore, the Commission proposed to require transmission providers to explain on compliance how their process will identify a plausible and diverse set of Long-Term Scenarios.[1170]

[1169] The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at PP 451-454.

[1170] NOPR, 179 FERC ¶ 61,028 at P 123.

**b. Comments**

541. Many commenters support requiring transmission providers in each transmission planning region to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[1171] GridLab and R Street state that this proposed requirement appropriately balances the need to address uncertainty and risk factors associated with long-term transmission planning while limiting the complexity of the transmission planning process.[1172] PJM says that employing multiple scenarios will ensure that transmission providers' plans reflect changing needs while avoiding the risk of over-building.[1173] SEIA states that requiring four distinct Long-Term Scenarios will allow transmission providers to reflect the uncertainty inherent in long-term planning.[1174] AEE states that the Commission should establish a minimum number of scenarios as a

[1171] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8, 18; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18-19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4-5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8-9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 6-7; US Chamber of Commerce Initial Comments at 7; US DOE Initial Comments at 14; Vermont Electric and Vermont Transco Initial Comments at 2.

[1172] GridLab Initial Comments at 12; R Street Initial Comments at 6.

[1173] PJM Initial Comments at 74.

[1174] SEIA Initial Comments at 11.

baseline for compliance with any final rule.[1175] New York TOs support requiring the use of multiple scenarios for Long-Term Regional Transmission Planning, noting that NYISO already incorporates multiple scenarios into its transmission planning processes.[1176] Nevada Commission notes that information from four scenarios could provide inputs into Nevada's integrated regional planning process and identify both local and regional needs.[1177]

542. Policy Integrity argues that the Commission should require more than four Long-Term Scenarios.[1178] Policy Integrity identifies planning efforts that have used more than four scenarios to illustrate that best practice counsels against reducing the number of required Long-Term Scenarios.[1179] Northwest and Intermountain state that, depending upon the size and characteristics of the transmission planning region, additional scenarios may be necessary to identify the transmission facilities that are most likely to ensure just

[1175] AEE Reply Comments at 18.

[1176] New York TOs Initial Comments at 2.

[1177] Nevada Commission Initial Comments at 8-9.

[1178] Policy Integrity Initial Comments at 14-16.

[1179] *Id.* at 15 (citing US DOE et al., Presentation on National Transmission Planning Study at the Modeling Subcommittee Meeting, at slide 21 (June 7, 2022), https://perma.cc/MEJ5-9JE6 (study will use approximately 100 scenarios); ERCOT, Report On Existing and Potential Electric System Constrains and Needs 10 (Dec. 2020), https://perma.cc/JGS4-9VH7 (ERCOT has previously used five scenarios); Mohamed Labib Awad et al., *Using Market Simulations for Economic Assessment of Transmission Upgrades: Application of the California ISO Approach, in Restructured Electric Power Systems: Analysis Of Electricity Markets With Equilibrium Models* 241, 255 (Xiao-Ping Zhang ed. 2010) (economists evaluating CAISO have used seventeen scenarios)).

and reasonable rates.[1180] LADWP states that while developing more than four scenarios will likely be prudent in some instances such as special studies, four scenarios should be adequate for most Long-Term Regional Transmission Planning given the 20-year planning horizon and uncertainties.[1181]

543. Some commenters stress the importance of considering multiple Long-Term Scenarios and the uncertainty associated with future conditions.[1182] ACORE suggests that uncertainties in data can be addressed with multiple Long-Term Scenarios that are continuously revised instead of granting flexibility or encouraging discounting of certain factors.[1183] ENGIE states that a single base-case scenario is not effective at capturing trends in the resource mix and demand.[1184] New York Commission and NYSERDA state that Long-Term Scenarios should reflect a range of plausible long-term futures that are relevant to the state (or transmission planning region) and should account for the uncertainty associated with looking out over longer time horizons.[1185] On the other hand, R Street posits that whether scenario planning sufficiently captures information on the

[1180] Northwest and Intermountain Initial Comments at 12.

[1181] LADWP Initial Comments at 4.

[1182] ACORE Initial Comments at 10; ENGIE Initial Comments at 3-4; New York Commission and NYSERDA Initial Comments at 8; R Street Initial Comments at 6.

[1183] ACORE Initial Comments at 10.

[1184] ENGIE Initial Comments at 4.

[1185] New York Commission and NYSERDA Initial Comments at 8.

resource mix and demand depends more on the quality of inputs and scenario construction elements than the total number of scenarios.[1186]

544. Some commenters generally support requiring Long-Term Scenarios[1187] including scenarios examining the effects of high energy demand,[1188] and penetration of renewable resources.[1189]

545. Other commenters do not oppose this requirement.[1190]

546. Some commenters support requiring transmission providers to establish Long-Term Scenarios, but would modify the NOPR proposal to require a lower minimum number. AEP, Entergy, NRECA, Pine Gate, and Western PIOs support requiring at least three Long-Term Scenarios.[1191] CAISO argues that the Commission should not require transmission providers to develop a minimum of four Long-Term Scenarios because

[1186] R Street Initial Comments at 6.

[1187] Breakthrough Energy Supplemental Comments at 1; Clean Energy Associations Initial Comments at 11-12; Cross Sector Representatives Supplemental Comments at 1; PJM Initial Comments at 6, 71-72; RMI Supplemental Comments at 2; US Climate Alliance Initial Comments at 2; Western PIOs Initial Comments at 29.

[1188] ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

[1189] ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

[1190] Clean Energy Buyers Initial Comments at 17; Dominion Initial Comments at 25; Pine Gate Initial Comments at 26; Utah Division of Public Utilities Initial Comments at 5.

[1191] AEP Initial Comments at 5, 8, 12; Entergy Initial Comments at 13; NRECA Initial Comments 35; Pine Gate Initial Comments at 26-27; Western PIOs Initial Comments at 33.

there is no evidence, rationale, or justification for why four is the appropriate number of scenarios to develop.[1192] Instead, CAISO asserts that the Commission should grant transmission planners the flexibility to determine the minimum number of Long-Term Scenarios that are appropriate given the specific circumstances in their region and planning cycle. However, CAISO states that if Commission were to adopt a minimum number of Long-Term Scenarios, three Long-Term Scenarios is appropriate because it allows for a base case scenario and two sensitivity scenarios.[1193] Entergy and NRECA claim that three Long-Term Scenarios would better balance the burden with the benefit of developing an additional scenario.[1194] Pine Gate recommends that, instead of requiring a fourth scenario, the Commission should permit transmission providers in each transmission planning region to develop and use no less than three Long-Term Scenarios, and then to conduct either a fourth scenario or a sensitivity analysis on the most likely Long-Term Scenario to "account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low frequency events" as proposed in the NOPR.[1195]

[1192] CAISO Initial Comments at 23-24.

[1193] *Id.* at 25-26.

[1194] Entergy Initial Comments at 13; NRECA Initial Comments 35.

[1195] Pine Gate Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

547. National Grid argues that there is an inherent trade-off between the number of Long-Term Scenarios, the quality of the data underpinning the assessment, and the frequency of reassessments. National Grid concludes that a transmission provider should not be required to plan for a scenario that is impossible or not supported by its stakeholders solely to meet the requirement that four distinct Long-Term Scenarios be developed and studied.[1196] Xcel supports the use of scenarios but states that the proposed requirement to use at least four Long-Term Scenarios is too prescriptive.[1197] Relatedly, LADWP states that developing more than four Long-Term Scenarios may be prudent in some instances but that it would be inefficient and a waste of resources to require all transmission providers in each transmission planning region to do so.[1198]

548. Some commenters broadly oppose the NOPR proposal to require transmission providers in each transmission planning region to develop at least a minimum number or specific number of Long-Term Scenarios.[1199] California Commission argues that the NOPR's approach would interfere with regional transmission planning processes, such as CAISO's, that are closely coordinated with state resource planning and load forecasting

[1196] National Grid Initial Comments at 14-15.

[1197] Xcel Initial Comments at 10.

[1198] LADWP Initial Comments at 4.

[1199] California Commission Initial Comments at 21-24; Duke Initial Comments at 15; Indicated PJM TOs Initial Comments at 9-10; ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30; OMS Initial Comments at 5; PG&E Initial Comments at 6-7; SPP Initial Comments at 9-10; State Agencies Initial Comments at 14.

and already effectively identify transmission necessary to accommodate changes in the resource mix and demand.[1200] Duke argues that requiring a minimum number of Long-Term Scenarios, while also requiring one capture high-impact, low-frequency events, places greater importance on developing scenarios purely to satisfy the requirement than on gaining consensus about what scenarios are in fact plausible or most likely.[1201] MISO states that a prescriptive number of Long-Term Scenarios with specific factors included may introduce a level of granularity and complexity into Long-Term Regional Transmission Planning that impedes progress.[1202]

549. Some commenters request that the Commission provide transmission providers in each transmission planning region with the flexibility to determine how many Long-Term Scenarios to develop.[1203] US DOE supports a requirement to identify four scenarios as a reasonable lower bound, and supports the analysis of additional scenarios, including sensitivities, but asserts that the development of Long-Term Scenarios should not be prescriptive but, rather, the Commission should provide guidelines and give transmission

[1200] California Commission Initial Comments at 23.

[1201] Duke Initial Comments at 15.

[1202] MISO Initial Comments at 20.

[1203] Ameren Initial Comments at 13-14; Avangrid Initial Comments at 9-10; CAISO Initial Comments at 25; California Energy Commission Initial Comments at 2; Clean Energy Associations Initial Comments at 11-12; Dominion Initial Comments at 25; Entergy Initial Comments at 13; MISO Initial Comments at 16, 20; MISO TOs Initial Comments at 16-17; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 5; PG&E Initial Comments at 7; PJM Initial Comments at 72; SPP Initial Comments at 9; US DOE Initial Comments at 14; Xcel Initial Comments at 10.

planning regions flexibility to work within those guidelines to capture reasonable sets of scenarios.[1204]

550. Some commenters propose that, if the Commission does not require a minimum number of Long-Term Scenarios, the Commission should instead require that transmission providers in each transmission planning region demonstrate, on compliance, why their proposed number of Long-Term Scenarios is appropriate.[1205] Duke asserts that the Commission should direct transmission providers to offer on compliance a process for Long-Term Scenario development that will capture enough sufficiently plausible scenarios with distinct sets of assumptions to adequately capture a consensus view of the most likely future state(s) to occur.[1206]

551. Other commenters call for the Commission to permit discretion on how transmission providers determine the number of Long-Term Scenarios to use.[1207] ISO-NE and ISO/RTO Council argue that the number of Long-Term Scenarios is an implementation detail that each transmission planning region should decide.[1208] NYISO

[1204] US DOE Initial Comments at 14.

[1205] CAISO Initial Comments at 25; Duke Initial Comments at 15; Eversource Initial Comments at 17-18; NESCOE Initial Comments at 30-31.

[1206] Duke Initial Comments at 15.

[1207] Indicated PJM TOs Initial Comments at 9-10; ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30-31; OMS Initial Comments at 5.

[1208] ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9.

states that the final rule should permit each transmission planning region to conduct Long-Term Regional Transmission Planning using multiple Long-Term Scenarios that account for varying levels of achievement of local laws and regulations.[1209]

552. MISO opposes requiring transmission providers to evaluate a specific number of Long-Term Scenarios and proposes, instead, that the Commission require that future scenarios be developed and implemented for purposes of long-term regional transmission planning, leaving each transmission planning region to determine what and how many scenarios are appropriate. According to MISO, this approach would ensure consistency across the transmission planning regions in what is required while allowing for any needed variation within each region.[1210] Additionally, MISO notes that it developed the futures that it uses in its Long-Range Transmission Plan through extensive stakeholder processes and that these futures reflect the specific realities of its member utilities. MISO contends that allowing transmission providers to develop the number of Long-Term Scenarios they need, and at intervals appropriate for them, encourages stakeholder buy-in and more efficient allocation of planning resources.[1211]

553. California Municipal Utilities disagree with comments that urge prescriptive uniformity, arguing that uniformity involves high costs and lacks consumer protection

[1209] NYISO Initial Comments at 23.

[1210] MISO Initial Comments at 16, 20.

[1211] MISO Reply Comments at 9-10.

measures against speculative transmission projects.[1212] For example, California Municipal Utilities argue against the proposal from Western PIOs for the development of three common scenarios to be synchronized across the Western Interconnection because this proposal amounts to central resource planning, which is not consistent with the existing process in which state and local choices drive the planning process.[1213]

554. Louisiana Commission states that the Commission's proposal is overly prescriptive and that the Commission should provide for a more flexible approach that allows transmission providers, retail regulators, and other stakeholders to develop scenarios with appropriate, realistic, and reasonable assumptions. Louisiana Commission states that Long-Term Scenarios should be based on reasonable ranges of assumptions for load, and generation type and location. Louisiana Commission argues that the number of scenarios required is far less important than the quality of the data and assumptions used to develop them.[1214] MISO TOs agree that the NOPR proposal is overly prescriptive, stating that the Commission should not create unnecessary obstacles, but rather create a rule broad enough to incorporate existing processes.[1215]

555. Some commenters emphasize the need for an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to provide timely

[1212] California Municipal Utilities Reply Comments at 5.

[1213] *Id.* (citing Western PIOs Initial Comments at 32-33).

[1214] Louisiana Commission Reply Comments at 6-7.

[1215] MISO TOs Reply Comments at 13.

and meaningful input into which Long-Term Scenarios are developed.[1216] For example, California Commission, NRECA, Concerned Scientists, and US Climate Alliance support the NOPR proposal to require transmission providers to disclose—subject to any applicable confidentiality protections—information and data inputs that they use to create each Long-Term Scenario.[1217] ELCON states that the Commission should require each transmission provider to post all methodologies and inputs used in determining Long-Term Scenarios and factors to its OASIS.[1218] NRG claims that the NOPR proposes a central determination of particular actions based on collectively determined assumptions, which gives up a major advantage of competition – the requirement that market participants take an individual view based on available information of the future viability of any investment they might make.[1219]

556. NESCOE argues that states must play a central role in Long-Term Regional Transmission Planning. Specifically, NESCOE agrees with ISO-NE, which calls for the Commission to explicitly authorize states to have a central decision-making role at all

[1216] California Commission Initial Comments at 25; Clean Energy Associations Initial Comments at 12; DC and MD Offices of People's Counsel Initial Comments at 14; ELCON Initial Comments at 12; NRECA Initial Comments at 35; Pacific Northwest State Agencies at 14-15; US Climate Alliance Initial Comments at 2.

[1217] California Commission Initial Comments at 25; NRECA Initial Comments at 35; Concerned Scientists Reply Comments at 15-16; US Climate Alliance Initial Comments at 2.

[1218] ELCON Initial Comments at 12.

[1219] NRG Initial Comments at 8.

aspects of Long-Term Regional Transmission Planning, including "scenario analysis development," to ensure necessary additional investment for a reliable, clean energy future.[1220] Similarly, Nebraska Commission adds that state regulatory commissions should have a significant role in defining Long-Term Scenarios.[1221]

557. AEE requests that the Commission clarify the role of states in providing input to the development of Long-Term Scenarios.[1222]

558. GridLab states that the Commission should be prepared to act as the arbiter of stakeholder concerns about Long-Term Scenario design, similar to the role that state public utility commissions play in the integrated resource planning process, and that this may require new staff, resources, and the development of new expertise at the Commission.[1223]

### c. Commission Determination

559. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. In implementing this requirement, transmission providers must develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term

[1220] NESCOE Reply Comments at 2 (citing ISO-NE Initial Comments at 2-4).

[1221] Nebraska Commission Initial Comments at 5-6.

[1222] AEE Initial Comments at 19.

[1223] GridLab Initial Comments at 11-12.

Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section above. We find that requiring transmission providers to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning strikes the appropriate balance between establishing a sufficient number of Long-Term Scenarios and the associated burden of developing and using Long-Term Scenarios in Long-Term Regional Transmission Planning. We also find that requiring transmission providers to develop at least three distinct Long-Term Scenarios instead of four, as proposed in the NOPR, is more consistent with the manner in which some transmission providers currently employ scenarios in their existing regional transmission planning process.[1224] We also reiterate, as stated in the NOPR, that if transmission providers produce a base-case Long-Term Scenario in Long-Term Regional Transmission Planning, that base case should be consistent with what the transmission provider determines is the most likely scenario to occur.[1225]

560. In addition, we adopt the NOPR proposal to require, consistent with Order No. 890's transparency transmission planning principle, transmission providers in each

[1224] *See, e.g.*, CAISO Initial Comments at 26 (explaining that "CAISO typically has utilized three scenarios in its public policy planning process, a base case scenario and two sensitivity scenarios"); Entergy Initial Comments at 13-14 (explaining that MISO currently uses three scenarios in its transmission planning process and arguing that the use of three scenarios enables "transmission providers to 'bookend' plausible outcomes to plan no-regrets additions to meet the grid, and then develop a scenario between those two to better inform the decision making"); NRECA Initial Comments at 35 n.100 (highlighting that MISO uses three scenarios in its transmission planning process).

[1225] NOPR, 179 FERC ¶ 61,028 at P 123.

transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs that they use to create each Long-Term Scenario.[1226] We also adopt the NOPR proposal to require transmission providers in each transmission planning region, consistent with Order No. 890's coordination transmission planning principle, to provide stakeholders an opportunity to provide timely and meaningful input into how Long-Term Scenarios are developed.[1227] Consistent with Order No. 890 and Order No. 1000's coordination transmission planning principle, we require transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders. Furthermore, we adopt the NOPR proposal to require transmission providers to revise the regional transmission planning process in their OATTs to outline an open and transparent process that provides stakeholders, including

[1226] The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

[1227] The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at P 454.

states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. We conclude that these requirements will help ensure that transmission providers will have the necessary information to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. Furthermore, by requiring transmission providers to afford stakeholders a meaningful opportunity to propose future outcomes that are probable, we believe that this requirement helps to ensure that Long-Term Transmission Needs are being addressed in a more efficient or cost-effective manner.[1228]

561. We also note the important role of states in developing Long-Term Scenarios. As the Commission stated in Order No. 890 and Order No. 1000, and we reiterate here, our expectation is that "all transmission providers will respect states' concerns" when engaging in the regional transmission planning process.[1229] We strongly encourage states to participate actively in the development of Long-Term Scenarios, as well as in all other aspects of Long-Term Regional Transmission Planning. In response to NESCOE's and AEE's concerns about the role of state regulators in the development of Long-Term Scenarios and their use in Long-Term Regional Transmission Planning,[1230] we find that,

[1228] Order No. 1000, 136 FERC ¶ 61,051 at P 150.

[1229] *Id.* P 212; Order No. 890, 118 FERC ¶ 61,119 at P 574.

[1230] AEE Initial Comments at 8; NESCOE Reply Comments at 2 (citing ISO-NE Initial Comments at 2-4).

consistent with Order No. 890,[1231] transmission planning must be coordinated with interested stakeholders, including relevant state regulators that wish to participate in the Long-Term Regional Transmission Planning process. As reflected throughout this final rule, we recognize that states have a particularly important role to play in the development of Long-Term Regional Transmission Facilities and encourage transmission providers to work with states in a way that reflects that role in addition to complying with the relevant requirements established herein.

562. In response to commenters that argue that the Commission should require four or more Long-Term Scenarios,[1232] we affirm that nothing in this final rule precludes or prevents transmission providers from proposing to use more than three Long-Term Scenarios in Long-Term Regional Transmission Planning. To the extent that transmission providers, in consultation with stakeholders, conclude that using more than three Long-Term Scenarios is appropriate for Long-Term Regional Transmission

[1231] Order No. 890, 118 FERC ¶ 61,119 at P 574.

[1232] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18-19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4-5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8-9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 7; US Chamber of Commerce Initial Comments at 7; US DOE Initial Comments at 14-15; Vermont Electric and Vermont Transco Initial Comments at 2.

Planning in their transmission planning region, those transmission providers may propose to use more than three Long-Term Scenarios in their compliance filings.

563. In response to California Commission's comments about the interaction between the development of Long-Term Scenarios and existing regional transmission planning processes,[1233] we believe the final rule, as modified from the NOPR proposal, addresses this concern and provides transmission providers with sufficient flexibility to tailor the development of Long-Term Scenarios to their transmission planning regions' specific needs or existing practices, as discussed elsewhere in this final rule.[1234]

### 5. Types of Long-Term Scenarios

#### a. NOPR Proposal

564. In the NOPR, the Commission proposed to require that each Long-Term Scenario incorporate, at a minimum, the categories of factors listed in the requirement above. As discussed in the Factors section of the NOPR,[1235] the Commission proposed that each Long-Term Scenario must be consistent with federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans. However, the Commission explained that each Long-Term Scenario may vary according

[1233] California Commission Initial Comments at 23.

[1234] *See supra* Categories of Factors, Requirement to Incorporate Categories of Factors section; Categories of Factors, Stakeholder Process and Transparency section.

[1235] NOPR, 179 FERC ¶ 61,028 at PP 104-112.

to assumptions about the remaining categories of factors described in the NOPR, as well as with respect to other characteristics of the future electric power system. The Commission explained that it neither proposed to require the development of a specific Long-Term Scenario or specific set of Long-Term Scenarios, nor did it propose to require that transmission providers identify the relative likelihood of different Long-Term Scenarios except where transmission providers develop a base case scenario, as described more fully below.[1236]

565. The Commission proposed to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.[1237] The Commission explained that the set of at least four Long-Term Scenarios must be: (1) plausible, that is they must reasonably capture probable future outcomes, and (2) diverse in the sense that transmission providers must be able to distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario. The Commission proposed to require that if the transmission providers in a transmission planning region use a base case scenario, that scenario should be consistent with the scenario that the transmission providers determine to be the most likely scenario to occur.

[1236] *Id.* P 121.

[1237] The Commission noted that different assumptions about the factors and data inputs used to develop Long-Term Scenarios and other characteristics of the future electric power system determine whether the set of Long-Term Scenarios are plausible and diverse.

**b. Comments**

566. Some commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.[1238] For example, GridLab agrees that the Commission should require that transmission providers demonstrate that their Long-Term Scenarios capture a reasonable range of possible futures. GridLab argues that scenarios that are too conservative will lead to similar load-resource and transmission portfolio scenarios, which limits the value of scenario planning in managing uncertainty and risk.[1239] Illinois Commission argues that the NOPR's proposed requirement for diverse and plausible scenarios is important, and that Long-Term Scenarios must consider a wide array of conditions.[1240]

567. Some commenters discuss the need for certain types of Long-Term Scenarios.[1241] Certain TDUs and PIOs argue that, although Long-Term Scenarios should include

[1238] APPA Initial Comments at 29; Clean Energy Buyers Initial Comments at 17; DC and MD Offices of People's Counsel Initial Comments at 13; GridLab Initial Comments at 11 & n.12; Illinois Commission Initial Comments at 7; Mississippi Commission Reply Comments at 9; NARUC Initial Comments at 10; NESCOE Initial Comments at 32; New York Commission and NYSERDA Initial Comments at 8; SPP Market Monitor Initial Comments at 7.

[1239] GridLab Initial Comments at 11.

[1240] Illinois Commission Initial Comments at 7.

[1241] ACORE Initial Comments at 10-11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18; Clean Energy Associations Initial Comments at 10-11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 18-19; Georgia Commission Initial Comments at 4-5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22-23; PJM

anticipated levels of generation, they should also include "book end" scenarios of high- and low-load growth.[1242] Clean Energy Associations argue that, because the Inflation Reduction Act provides for significant funding for electrification, at least some scenarios should evaluate transmission needs under higher-than-anticipated load growth.[1243]

568. PJM describes four scenarios that it might use: (1) a low uncertainty scenario with known inputs, such as legislative and regulatory laws and announced deactivations and load forecasts; (2) a medium uncertainty scenario that includes state and local goals and economic retirement analysis; (3) a higher uncertainty scenario that adds more speculative and aspirational goals; and (4) a high-impact-low-frequency resilience evaluation scenario that includes low-probability, high-impact events. PJM states that the scenarios should be: (1) based on a clearly defined, robust set of factor development criteria grounded in customer needs; (2) capable of adapting to an evolving set of future system conditions; and (3) crafted to produce the appropriate level of transmission.[1244]

569. Western PIOs state that one scenario should be based on existing policy and assumptions about generation retirements and electrification that are likely to occur.

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Initial Comments at 73-74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5-6; Western PIOs Initial Comments at 33.

[1242] Certain TDUs Initial Comments at 18; PIOs Initial Comments at 22-23.

[1243] Clean Energy Associations Initial Comments at 11 (citing Inflation Reduction Act, Pub. L. No. 117-169 (2022)).

[1244] PJM Initial Comments at 73-74.

Western PIOs state that a second scenario would build on that base case scenario by assuming Public Policy Requirements and utility and corporate goals are met or exceeded, as well as high levels of electrification and generation retirements. Western PIOs state that a third scenario should address high-impact, low-frequency extreme weather events. Western PIOs state that the fourth scenario could be reserved for a scenario unique to each of the non-RTO/ISO transmission planning regions.[1245]

570. ACORE argues that uncertainties in data do not require granting flexibility or encouraging discounting, but instead can be addressed with multiple scenarios that are continuously revised as recommended in the NOPR. For example, one Long-Term Scenario can include a discounted set of goals, while another can add contingency factors for when demand exceeds those goals; and a range of scenarios could be incorporated for the extent of electrification of buildings and transportation. ACORE states that scenario analysis should incorporate a probabilistic-based range of future weather and extreme events which, ACORE asserts, will support the analyses of the benefits of mitigation of those extreme events and system contingencies and mitigation of weather and load uncertainty.[1246]

571. AEE recommends that the Commission require Long-Term Scenarios that consider anticipated distributed energy resource deployments.[1247] Evergreen Action

[1245] Western PIOs Initial Comments at 33.

[1246] ACORE Initial Comments at 10-11.

[1247] AEE Initial Comments at 8.

urges the Commission to require that at least one Long-Term Scenario contemplate a 100% clean-energy grid by 2035, to reflect the Biden Administration's target of 100% carbon-free electricity by 2035.[1248] Similarly, NextEra argues that the Commission should require that one of the Long-Term Scenarios be based on an economy-wide, net-zero emissions scenario or at least a federal net-zero emissions mandate limited to the power sector.[1249] In contrast, Utah Division of Public Utilities states that one of the Long-Term Scenarios should consider little or no state renewable energy or decarbonization goals or requirements to assist in determining transmission costs for states that have less onerous goals.[1250]

572. APPA requests that one of the Long-Term Scenarios represent a base case of business as usual.[1251] Eversource supports the NOPR proposal to use the "most likely scenario to occur" as the base case for analysis of Long-Term Scenarios.[1252] Georgia Commission argues that a base case scenario should reflect the expected long-term mix of generating capacity, with additional scenarios reflecting alternative carbon emission constraints, fuel prices, and growth in distributed energy resources.[1253] US Climate

[1248] Evergreen Action Initial Comments at 3.

[1249] NextEra Initial Comments at 65.

[1250] Utah Division of Public Utilities Initial Comments at 5-6.

[1251] APPA Initial Comments at 29.

[1252] Eversource Initial Comments at 19.

[1253] Georgia Commission Initial Comments at 4-5.

Alliance states that business-as-usual cases should be consistent with state and federal policy and used in addition to alternative scenarios that demonstrate a range of factors influencing the changing grid.[1254]

573. However, PIOs state that the Commission should not use the phrase "business as usual" as it is misleading in a rapidly changing electric industry.[1255] US DOE argues against identifying the likelihood of any one Long-Term Scenario, including a base case scenario, because identifying a single such scenario as most likely is challenging and discourages the analysis of more scenarios and sensitivities, undermining the value of scenario analysis. Instead, US DOE argues that transmission facilities that provide high value in multiple scenarios should be identified as more likely to provide value to the future transmission system, because expansion options that provide high value in many future scenarios are flexible, and that flexibility to accommodate multiple future scenarios is more important than trying to characterize the likelihood of any one scenario.[1256]

574. Senator Schumer supports requiring a high variable energy resource penetration scenario.[1257]

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[1254] US Climate Alliance Initial Comments at 2.

[1255] PIOs Initial Comments at 22.

[1256] US DOE Initial Comments at 15.

[1257] Senator Schumer Supplemental Comments at 2.

### c. Commission Determination

575. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of at least three Long-Term Scenarios. Specifically, we find that the set of at least three Long-Term Scenarios must be: (1) plausible, meaning that each scenario must itself be reasonably probable, and collectively that the set of plausible scenarios must reasonably capture probable future outcomes, and (2) diverse, in the sense that transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each Long-Term Scenario. We find that requiring Long-Term Scenarios to be both plausible and diverse prevents the development of Long-Term Scenarios that may otherwise be too conservative, speculative, or similar for transmission providers to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. Absent a requirement that Long-Term Scenarios be both plausible and diverse, transmission providers could develop Long-Term Scenarios in a manner that undercuts one of the primary benefits of using scenario-based planning practices, which is to help ensure that transmission providers can account for the uncertainty about future conditions when conducting Long-Term Regional Transmission Planning.

576. Moreover, we also require that each *individual* Long-Term Scenario be plausible (i.e., individually the scenario must be reasonably probable) because, absent such a requirement, we are concerned that the set of Long-Term Scenarios may include a Long-Term Scenario that rests on assumptions about the factors and data inputs that do not

reasonably capture possible future outcomes. Additionally, we also clarify the term "diverse" to mean that the *set* of Long-Term Scenarios must represent a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.

577. We disagree with commenters that argue that the Commission should modify the NOPR proposal and prescribe specific types of Long-Term Scenarios for transmission providers to use in Long-Term Regional Transmission Planning.[1258] We are not persuaded that we should require transmission providers to develop either a specific Long-Term Scenario or a specific set of Long-Term Scenarios because we believe that transmission providers, with an opportunity for timely and meaningful input from stakeholders, are in the best position to determine which plausible Long-Term Scenarios are applicable to their transmission planning region. Further, we do not find it necessary to require transmission providers to develop low-, medium-, and high-level assumptions for the factors that transmission providers believe to be important except where transmission providers develop a base case scenario, as discussed above.[1259]

[1258] ACORE Initial Comments at 10-11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18, 22; Clean Energy Associations Initial Comments at 11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 19; Georgia Commission Initial Comments at 4-5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22-23; PJM Initial Comments at 73-74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5-6; Western PIOs Initial Comments at 33.

[1259] *See supra* Types of Long-Term Scenarios section.

### 6. Sensitivities for High-Impact, Low-Frequency Events

#### a. NOPR Proposal

578. In the NOPR, the Commission proposed to require that at least one of the four distinct Long-Term Scenarios that transmission providers in each transmission planning region use in Long-Term Regional Transmission Planning account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. The Commission proposed to allow transmission providers the flexibility to determine which high-impact, low-frequency event should be modeled in this Long-Term Scenario as part of Long-Term Regional Transmission Planning based on the Commission's understanding that each transmission planning region may see a need to evaluate a different type of high-impact, low-frequency event. The Commission stated that high-impact, low-frequency events may include extreme weather events or events associated with potential cyber-attacks. The Commission explained that this Long-Term Scenario accounting for a high-impact, low-frequency event can be developed, for example, by assuming greater-than-expected electricity demand and greater-than-expected generation or transmission outages. The Commission proposed that the use of either probabilistic transmission planning[1260] or

[1260] NOPR, 179 FERC ¶ 61,028 at P 124. The Commission stated that it considers probabilistic transmission planning approaches to include any transmission planning approach that uses a probability distribution to assign probabilities to one or more inputs to the transmission model. The Commission stated that these inputs can include shorter-term operational inputs (like wind generation or generation outages). The Commission described stochastic techniques as including adaptive transmission planning techniques that identify transmission facilities that optimize transmission net-benefits over a time

stochastic techniques would be sufficient to satisfy this requirement, but it did not propose to require either approach at this time.[1261]

579. The Commission noted that transmission providers can develop sensitivities for every Long-Term Scenario to assess how outcomes modeled in Long-Term Scenarios may depend on an assumption about electric power system model inputs that does not vary across scenarios (e.g., higher natural gas prices). The Commission explained that such sensitivities can provide valuable information about the need for and benefits of potential transmission facilities, but also noted that they can be burdensome to develop if applied to every scenario.[1262]

**b. Comments**

580. Some commenters support the NOPR proposal to require one Long-Term Scenario to account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events as part of Long-Term Regional Transmission Planning.[1263] Ameren states that the inclusion of such events in Long-Term Regional Transmission Planning would provide additional information for

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horizon under market and regulatory uncertainty about the future. *Id.* P 124 n.228.

[1261] *Id.* P 124.

[1262] *Id.* P 125.

[1263] Ameren Initial Comments at 13; Arizona Commission Initial Comments at 6; California Commission Initial Comments at 24; Evergreen Action Initial Comments at 4; Eversource Initial Comments at 18; Grid United Initial Comments at 4; New England for Offshore Wind Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 14; US DOE Initial Comments at 15.

transmission providers, stakeholders, state regulators, and others to consider when determining the need for regional transmission facilities.[1264] According to Arizona Commission, including such a scenario, and giving the transmission provider the discretion to determine what this should be for its region, may provide the added benefit of allowing state involvement in identifying the appropriate "high-impact" event to be analyzed. Arizona Commission additionally asserts that the Commission should require transmission providers to develop sensitivities for each Long-Term Scenario to better understand the range of benefits under each scenario.[1265]

581. Eversource supports the NOPR proposal given the increasing threat of extreme weather events and potential cyber-attacks.[1266] Similarly, Illinois Commission states that the inclusion of high-impact, low-frequency events in the transmission planning process is reasonable and should include cyber-security attacks and extreme weather events to strengthen the system's resilience.[1267] New England for Offshore Wind argues that it is prudent for the Commission to require transmission providers to develop at least one high-impact, low-frequency scenario due to the increased likelihood of extreme weather events due to climate change.[1268] SoCal Edison states that incorporating probabilistic

[1264] Ameren Initial Comments at 13-14.

[1265] Arizona Commission Initial Comments at 6-7.

[1266] Eversource Initial Comments at 18.

[1267] Illinois Commission Initial Comments at 6.

[1268] New England for Offshore Wind Initial Comments at 2.

assumptions about extreme weather in Long-Term Scenarios would be a reasonable, proactive approach to mitigate the impacts of extreme weather when it occurs.[1269]

582. Likewise, Cypress Creek, City of New Orleans Council, DC and MD Offices of People's Counsel, and PIOs support the inclusion of extreme weather events in Long-Term Scenarios.[1270] Business Council for Sustainable Energy contends that Long-Term Scenarios must account for the increase in significant climate events, acknowledging that the most salient events to assess may vary regionally.[1271] US DOE asserts that regional transmission planning should consider the effects of extreme events, including extreme weather events, on the availability and reliability of the transmission system.[1272] WE ACT comments that requiring transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events brought on by the climate crisis.[1273]

[1269] SoCal Edison Initial Comments at 12.

[1270] City of New Orleans Council Initial Comments at 8; Cypress Creek Reply Comments at 5-6; DC and MD Offices of People's Counsel Reply Comments at 6; PIOs Reply Comments at 10; *see also* RMI Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2-3.

[1271] Business Council for Sustainable Energy Initial Comments at 4.

[1272] US DOE Initial Comments at 5.

[1273] WE ACT Initial Comments at 2.

583. Other commenters express more general support for the study of high-impact, low-frequency events in Long-Term Regional Transmission Planning.[1274] Clean Energy Associations emphasize that no scenario or sensitivity should assume that historical operating conditions will persist given the unpredictable and increasing impact of climate change.[1275] Grid United states that high-impact, low-frequency scenarios should not be considered "black swan" events since they occur on a regular, but low-frequency, basis. Moreover, Grid United asks that the Commission define or provide examples of high-impact, low-frequency events that transmission providers could incorporate into Long-Term Scenarios to provide clarity and consistency across transmission planning regions.[1276]

584. NARUC does not oppose the requirement that one of the Long-Term Scenarios account for high-impact, low-frequency events but notes that states' input is important when developing such scenarios.[1277] Pattern Energy states that, with respect to low-probability, high-risk event scenarios, the Commission should: (1) require the North American Electric Reliability Corporation and the Regional Entities to develop the scope

[1274] *See* Business Council for Sustainable Energy Initial Comments at 4; Clean Energy Associations Initial Comments at 12; Evergreen Action Initial Comments at 3-4; Grid United Initial Comments at 4-5; NARUC Initial Comments at 11-12; NASUCA Initial Comments at 4-5; NESCOE Initial Comments at 32-33; NRECA Initial Comments at 35-36; Pattern Energy Initial Comments at 25; SoCal Edison Initial Comments at 12.

[1275] Clean Energy Associations Initial Comments at 12.

[1276] Grid United Initial Comments at 5.

[1277] NARUC Initial Comments at 11-12.

of low-probability, high-risk events for each region of the country and then (2) require transmission providers to model at least one of the events in a rotation of the three-year review of the 20-year plans to identify vulnerabilities that can be addressed through transmission solutions that increase resilience.[1278] Vermont Electric and Vermont Transco request clarity on what scenarios the Commission would consider sufficiently high-impact to be analyzed but not so high-impact as to be unable to be mitigated by effective Long-Term Regional Transmission Planning.[1279]

585. Some commenters support the Commission's proposal to permit transmission providers to model high-impact, low-frequency events via probabilistic or stochastic methods.[1280] PJM states that it will sometimes use probabilistically-derived parameters and sometimes use deterministically-derived parameters in its Long-Term Scenarios, depending on which is more appropriate.[1281] Policy Integrity asserts that the Commission should ensure the use of modeling techniques that address uncertainty, such as stochastic programming and robust optimization models.[1282] Policy Integrity argues that modeling that fails to consider uncertainties that arise from various factors could reduce the cost-

[1278] Pattern Energy Initial Comments at 25.

[1279] Vermont Electric and Vermont Transco Initial Comments at 3.

[1280] California Commission Initial Comments at 24-25; Eversource Initial Comments at 18; PJM Initial Comments at 74-75.

[1281] PJM Initial Comments at 75.

[1282] Policy Integrity Initial Comments at 7.

efficacy and efficiency of results and, ultimately, result in unjust and unreasonable rates.[1283] Policy Integrity cites the European Network of Transmission System Operators' consideration of the interactions between gas and electric systems as an example of best practices for choosing scenarios.[1284]

586. Some commenters provided views on the Commission's proposal to require transmission providers to develop sensitivities for each Long-Term Scenario.[1285] Business Council for Sustainable Energy states that it is important that scenario planning cover a range of sensitivities, and that the long-term needs of the transmission system as well as long-term policy goals should be incorporated.[1286] NERC states that studies could more adequately study various sensitivities and extreme conditions (e.g., extreme weather) to ensure a reliable, resilient, and secure bulk power system on a longer time horizon, which could, in turn, help inform transmission expansion plans particularly related to the changing resource mix.[1287]

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[1283] *Id.* at 6.

[1284] *Id.* at 9 (citing European Commission, Key Cross Border Infrastructure Projects, https://perma.cc/4U6X-Q2WN (last visited Aug. 9, 2022)).

[1285] Business Council for Sustainable Energy Initial Comments at 4; NERC Initial Comments at 7; Exelon Initial Comments 7 & n.7; GridLab Initial Comments at 17-19; Idaho Power Initial Comments at 5; Minnesota State Entities Initial Comments at 5; NYISO Initial Comments at 26; PIOs Initial Comments at 23-24; Policy Integrity Initial Comments at 14-16; PPL Initial Comments at 9; R Street Initial Comments at 6; US DOE Initial Comments at 15-16.

[1286] Business Council for Sustainable Energy Initial Comments at 4.

[1287] NERC Initial Comments at 7.

587. GridLab recommends that the Commission provide a high-level requirement and guidance on what kinds of factors are more effectively considered in scenario versus sensitivity analysis and how sensitivity analysis might be used in tandem with scenario analysis.[1288] Policy Integrity states that, instead of mandating only a minimum number of Long-Term Scenarios, the Commission should also require sensitivity analysis of critical drivers of transmission needs.[1289] In addition, Policy Integrity recommends that the Commission require transmission providers to run a sensitivity for each Long-Term Scenario using a 30-year transmission planning horizon and compare the results with those from the analysis of each Long-Term Scenario using a 20-year transmission planning horizon.[1290] PIOs state that the Commission should specify that, if any critical variable (e.g., natural gas prices, capital costs of wind and solar, short and long duration storage, and carbon capture and sequestration) is the same in more than two Long-Term Scenarios, then transmission providers must conduct sensitivities that use different values for that variable.[1291]

588. Although NRECA does not oppose the proposal that at least one Long-Term Scenario account for high-impact, low-frequency events from extreme weather, NRECA states that the Commission should not require any Long-Term Scenarios to account for

[1288] GridLab Initial Comments at 17-18.

[1289] Policy Integrity Initial Comments at 15.

[1290] *Id.* at 10-11.

[1291] PIOs Initial Comments at 23-24.

possible cyber-attacks. NRECA asserts that modeling cyber-attacks and their effects would be extraordinarily complex and risk disclosure of non-public Critical Electric Infrastructure Information (CEII) and that such risks are better addressed in North American Electric Reliability Corporation standards development, noting that cyber-attacks may already be evaluated under North American Electric Reliability Corporation Transmission Planning Reliability Standard TPL-001-4.[1292]

589. Some commenters oppose requiring one Long-Term Scenario for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events.[1293] LADWP asserts that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single points of failures.[1294] US Chamber of Commerce argues against requiring a Long-Term Scenario for high-impact, low-frequency events because, it asserts, the scope and impacts of such events on the transmission system can be infinite in number.[1295]

[1292] NRECA Initial Comments at 35-36 (citing GDS Associates, Report, at 13 (Aug. 17, 2022); NERC Reliability Standard TPL-001-4, Table 1 – Steady State, https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf).

[1293] LADWP Initial Comments at 3; MISO Initial Comments at 27-28, 38-39; Mississippi Commission Reply Comments at 6; OMS Initial Comments at 6; US Chamber of Commerce Initial Comments at 7.

[1294] LADWP Initial Comments at 3.

[1295] US Chamber of Commerce Initial Comments at 7.

590. MISO argues that, although the impacts of large-scale generation loss events associated with extreme weather events should be considered in Long-Term Regional Transmission Planning, the Commission should consider requiring analysis or sensitivities of extreme events that are focused on the times or snapshots when the system is potentially impacted by those events instead of requiring a separate extreme event scenario.[1296] MISO further argues that the Commission should not require a specific number or type of sensitivities, which can vary over time, but instead transmission providers should have flexibility to assess the appropriate sensitivities needed to test scenarios and results at the time those are being developed.[1297] Similarly, OMS argues that analyzing system performance during extreme weather for all Long-Term Scenarios would result in a better understanding of the benefits of transmission and ensure reliability regardless of future changes in generation and/or load.[1298] PIOs likewise recommend that the Commission require that transmission providers model extreme weather events as sensitivities in each Long-Term Scenario and, specifically, that they model at least extreme heat or cold over geographic areas that are experiencing these extremes.[1299]

[1296] MISO Initial Comments at 27-28.

[1297] *Id.* at 39.

[1298] OMS Initial Comments at 6.

[1299] PIOs Initial Comments at 21.

591. NESCOE states that it supports the study of high-impact, low-frequency events; however, NESCOE argues that the proposal raises questions about whether codifying such a requirement blurs the line between public policy planning and reliability planning, contrary to the NOPR's contention that none of the proposals seek to alter the reliability planning process. NESCOE contends that making the study of high-impact, low-frequency events discretionary instead of mandatory under Long-Term Regional Transmission Planning would avoid such tension.[1300] Mississippi Commission states that the Commission should not mandate that transmission planning attempt to predict extreme weather events and over-build the system, because "predicting where the next hurricane or tornado will land is speculative." Mississippi Commission argues that a better approach is to incorporate construction standards (e.g., North American Electric Reliability Corporation, IEEE, local reliability criteria) designed to withstand such events.[1301]

592. Idaho Power raises concerns that developing multiple sensitivities for multiple Long-Term Scenarios over a long-term transmission planning horizon introduces too many variables.[1302] Minnesota State Entities state that defining specific methods in the final rule—such as the difference between a "sensitivity" and what is included in a

[1300] NESCOE Initial Comments at 32-33.

[1301] Mississippi Commission Reply Comments at 6.

[1302] Idaho Power Initial Comments at 5.

"scenario"—can be unnecessarily confusing and complex.[1303] US DOE encourages transmission providers to perform sensitivity analyses but states that the Commission should only require that one Long-Term Scenario analyze high-impact, low-frequency events.[1304]

### c. Commission Determination

593. We modify the NOPR proposal to require transmission providers in each transmission planning region to develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1305] As discussed below, we acknowledge support in the record for studying high-impact, low-frequency events as proposed in the NOPR[1306] but also recognize that requiring a fourth Long-Term Scenario might be a burdensome way to study such events

[1303] Minnesota State Entities Initial Comments at 5.

[1304] US DOE Initial Comments at 16.

[1305] The Commission proposed in the NOPR to require that at least one of four Long-Term Scenarios account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. NOPR, 179 FERC ¶ 61,028 at P 124.

[1306] *See, e.g.*, New England for Offshore Wind Initial Comments at 2; *see also* Arizona Commission Initial Comments at 6-7. We also note that the Commission has previously discussed that "[e]xtreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future." Order No. 896, 183 FERC ¶ 61,191 at P 2.

as compared to a sensitivity.[1307] We find that more clearly defining the type of system conditions that transmission providers must model to account for uncertain operational outcomes—in particular, multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area—compared to the NOPR proposal, will enable transmission providers to better account for periods when regional transmission facilities may have particularly high value by decreasing the risk of loss of load and/or decreasing the cost to reliably serve load.

594. Therefore, we require that, after developing at least three Long-Term Scenarios, transmission providers develop a sensitivity for each of the Long-Term Scenarios.[1308] We provide transmission providers with flexibility to conduct this sensitivity either before or after identifying potential regional transmission solutions to the Long-Term Transmission Needs identified using those Long-Term Scenarios. Conducting this sensitivity before identifying potential regional transmission solutions can be useful because it may help transmission providers to identify such solutions. On the other hand, conducting this sensitivity after identifying potential regional transmission solutions to Long-Term Transmission Needs would allow transmission providers to engage in efforts

[1307] *See, e.g.*, MISO Initial comments at 27.

[1308] *See* NOPR, 179 FERC ¶ 61,028 at P 125 n.229. A sensitivity represents a single assumption about a short-term input or factor (some input with a value that may change throughout a day or year). A scenario represents an assumption about a longer-term input or factor (e.g., resource retirements and additions or public policies).

to develop additional or alternative regional transmission solutions to address such conditions.

595. In conducting this sensitivity, transmission providers change the data inputs of the underlying Long-Term Scenarios—in terms of load, generation, generator outages, and transmission outages—to account for uncertain operational outcomes that determine the benefits of or need for regional transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area, while maintaining the underlying longer-term determinants of the Long-Term Scenario (e.g., the installed capacity of each generation resource). The sensitivity can be thought of as a "stress test" for all Long-Term Scenarios.

596. We find it necessary to require the consideration of a more narrowly defined set of conditions, as compared to the broader high-impact, low-frequency event conditions described in the NOPR, to include multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1309] Extreme weather events have occurred more frequently in recent years,[1310] are periods when regional transmission facilities have particularly high value,[1311] and create system

[1309] *See, e.g.*, Grid United Initial Comments at 4-5 (stating that "the Commission should define or provide examples of the low-frequency, high impact events that it would like to be considered for planning purposes").

[1310] *See supra* The Overall Need for Reform section; *see also* NOPR, 179 FERC ¶ 61,028 at P 45; Breakthrough Energy Initial Comments at 8.

[1311] *See* ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5-6.

conditions that transmission providers can readily specify compared to contingencies with an unknown root cause.[1312] During these extreme weather events, generation and transmission outages can be widespread, occur at the same time, and persist due to a common cause like freezing temperatures or limited fuel availability. This more narrowly defined set of conditions also gives transmission providers more direct guidance on how to comply with the requirements of this final rule.[1313]

597. Although we are only requiring that one sensitivity analysis specific to extreme weather events be applied to each Long-Term Scenario to comply with this final rule, we do not preclude transmission providers from considering additional sensitivities. We recognize that transmission providers may consider several other sensitivities as important and helpful in evaluating the benefits of and need for Long-Term Regional Transmission Facilities. For example, transmission providers can develop sensitivities to account for a cyber-attack, significant forecast error, or fuel price volatility. We encourage transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.

598. We find that modeling extreme weather events as sensitivities is appropriate for Long-Term Regional Transmission Planning. We first note that extreme weather events

[1312] In terms of specifying the system conditions during extreme weather events, transmission providers can, for example, look at previous severe cold weather events to identify how load might increase, how load and generation forecasts might be incorrect, and how generation and transmission outages might occur during a future extreme weather event.

[1313] *See, e.g.*, Grid United Initial Comments at 4-5.

can occur under any assumed future scenario but do not, by themselves, represent changes in the way that factors are used in Long-Term Scenarios to determine Long-Term Transmission Needs.[1314] Therefore, we believe that applying a sensitivity to each Long-Term Scenario is a more accurate way to evaluate the effects of high-impact, low-frequency events than considering such events in a distinct Long-Term Scenario. Second, although there is a burden associated with conducting sensitivities, the overall burden of conducting a sensitivity analysis is comparatively lower than that of developing a new, separate Long-Term Scenario. This is because sensitivities will be conducted using the existing Long-Term Scenarios, where most inputs, and the factors and assumptions used to develop the scenarios, have already been established and mapped. Adjusting a set of existing inputs to test the impact of the changes on a Long-Term Scenario through a sensitivity analysis is therefore less burdensome than developing an entirely new Long-Term Scenario.

599. In addition, we highlight that transmission providers can use the required sensitivity analyses to evaluate the need for, or benefits of, increased Interregional Transfer Capability provided by candidate Long-Term Regional Transmission Facilities. We recognize that certain Long-Term Regional Transmission Facilities could increase Interregional Transfer Capability by changing the topology of the transmission system, even if the specific transmission facility is not directly connected to a neighboring transmission planning region's transmission system. We believe that an increase in

[1314] *See* MISO Initial Comments at 27-28; OMS Initial Comments at 6.

Interregional Transfer Capability could provide significant benefits during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages.[1315] We note that several commenters discuss the need for greater Interregional Transfer Capability because of extreme weather events[1316] and the importance of modeling extreme weather event conditions to capture the benefits of regional transmission facilities.[1317] As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to consider increased Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility when measuring Benefit 6.[1318] We believe that transmission providers can evaluate Benefit 6, including reduced loss of load and reduced production costs during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages, using this required sensitivity, among other

[1315] *See, e.g.*, Order No. 896, 183 FERC ¶ 61,191 at PP 85-88.

[1316] BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Kansas Commission Initial Comments at 8-9; NARUC Initial Comments at 23; US DOE Initial Comments at 39-42; *see also* ELCON Initial Comments at 8 (arguing Interregional Transfer Capability should be a driver of transmission needs); PJM Initial Comments at 66-67.

[1317] *See* ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5-6.

[1318] *See infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

sensitivities that transmission providers may develop to capture extreme events and system contingencies.

600. We disagree with NESCOE's concern that a requirement to study the impact of high-impact, low-frequency events might "blur[] the line between public policy planning and reliability planning."[1319] Rather, as discussed below in the Evaluation of the Benefits of Regional Transmission Facilities section, we believe that the requirement complements Benefit 6 (Mitigation of Extreme Weather Events and Unexpected System Conditions) given the high probability that extreme weather events will cause unplanned transmission outages and the likelihood that such events will continue to occur at regular intervals.[1320] Although this final rule requires a more comprehensive consideration of benefits, it does not alter Order No. 1000's requirements for transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the transmission planning region's reliability and economic requirements.

601. We also acknowledge LADWP's concern that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single point failure.[1321] Although we do not

[1319] NESCOE Initial Comments at 33.

[1320] *See infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

[1321] LADWP Initial Comments at 3.

preclude transmission providers from conducting such a study, such a study would not meet the final rule's requirement to conduct a sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.

### 7. Specificity of Data Inputs

#### a. NOPR Proposal

602. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to use "best available data inputs" when developing Long-Term Scenarios.[1322] The Commission stated that, by "best available," the Commission did not imply that there is a single "best" value for each data input that transmission providers must use, but rather that best practices are used to develop that data input.[1323]

603. The Commission proposed to define "best available data inputs" as data inputs that are timely and developed using diverse and expert perspectives, adopted via a process that satisfies the Order Nos. 890 and 1000 transparency transmission planning principles described above, and reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios.[1324] The Commission explained that an example

[1322] NOPR, 179 FERC ¶ 61,028 at PP 130-134.

[1323] *Id.* P 130.

[1324] *Id.* P 131.

of data inputs that could meet this requirement are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. The Commission stated that another example of data inputs that could meet this requirement are the most recent data on renewable energy potential and distributed energy resources developed by national labs.[1325]

604. The Commission proposed to require transmission providers in each transmission planning region to update all data inputs each time they reassess and revise, as necessary, their Long-Term Scenarios, which, as explained in the NOPR, the Commission proposed to require that they do at least every three years. As indicated in the Long-Term Regional Transmission Planning section of the NOPR,[1326] the Commission also proposed to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process through which transmission providers determine which data inputs to use in their Long-Term Scenarios. For example, consistent with the coordination transmission planning principle established in Order No. 890, the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input concerning which data inputs to use in Long-Term Scenarios.[1327]

[1325] *Id.* P 131 n.247.

[1326] *Id.* PP 64-67.

[1327] *Id.* P 132.

605. The Commission preliminarily found that a requirement to use the best available data inputs was necessary to ensure that transmission providers are regularly updating data inputs and then using timely and accurate data inputs to inform Long-Term Scenarios. The Commission stated that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, the Commission explained that data inputs can directly affect which transmission facilities may be selected and, in turn, Commission-jurisdictional rates.[1328]

**b. Comments**

**i. Interest in Best Available Data Requirement**

606. Many commenters generally support the NOPR proposal for "best available data," but some recommend that the Commission monitor data inputs.[1329] AEE states that it is not practical to make a more prescriptive requirement for data inputs than the NOPR proposal and recommends that the Commission be vigilant in monitoring data inputs.[1330] Policy Integrity states that the NOPR proposal is crucial in protecting against strategic

[1328] *Id.* P 133.

[1329] AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17-18; DC and MD Offices of People's Counsel Initial Comments at 14; Duke Initial Comments at 16-17; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ITC Initial Comments at 12; NARUC Initial Comments at 13-15; NRECA Initial Comments at 35-36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13-14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 6; US DOE Initial Comments at 16-17; WATT Coalition Initial Comments at 7.

[1330] AEE Initial Comments at 23.

modeling behavior.[1331] WATT Coalition adds that "best available data" on future generation must be used because demand and energy profiles are inherently uncertain.[1332]

607. ACEG claims that the FPA supports the Commission's proposed requirement to plan based on the best available data, noting that section 217(b)(4) requires the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligation of load-serving entities."[1333] ACEG argues that load-serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies.[1334]

608. Clean Energy Buyers state that it is important to get stakeholder input on data inputs, as has been done through MISO's Long-Range Transmission Planning effort.[1335] Breakthrough Energy states that Long-Term Scenarios should use "best available data."[1336]

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[1331] Policy Integrity Initial Comments at 17.

[1332] WATT Coalition Initial Comments at 7.

[1333] ACEG Initial Comments at 26-27 (citing 16 U.S.C. 824q(b)(4)).

[1334] *Id.* at 27.

[1335] Clean Energy Buyers Initial Comments at 18.

[1336] Breakthrough Energy Supplemental Comments at 1.

### ii. Reservations with the Best Available Data Requirement

609. Several commenters support the NOPR proposal but nevertheless have suggestions about how to modify the proposal.[1337] For example, several commenters request that the Commission create a common dataset, publish a database of best available sources of data, or otherwise standardize data inputs.[1338] Southeast PIOs state that the Commission should publish a regularly updated database of best available data sources and require transmission providers to justify any decision not to use that database, arguing that flexibility in project selection can only work if the selection process utilizes reliable and standardized inputs.[1339] SEIA urges the Commission to issue standards or guidelines that define what constitutes "best available data inputs" for each of the seven categories of factors.[1340] R Street contends that intraregional standardization could support internal consistency and transparency and focus scarce stakeholder capital.[1341]

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[1337] ACEG Initial Comments at 7; ACORE Initial Comments at 8-9; Eversource Initial Comments at 20-21; GridLab Initial Comments at 23; OMS Initial Comments at 5; Pine Gate Initial Comments at 27-29; PIOs Initial Comments at 19-20; Policy Integrity Initial Comments at 6, 16-18; Southeast PIOs Initial Comments at 47-48.

[1338] ACEG Initial Comments at 7; ACORE Initial Comments at 8-9; GridLab Initial Comments at 23; PIOs Initial Comments at 19-20; Southeast PIOs Initial Comments at 47-48.

[1339] Southeast PIOs Initial Comments at 47.

[1340] SEIA Initial Comments at 11; SEIA Reply Comments at 4.

[1341] R Street Initial Comments at 7.

610. ELCON notes that, as part of the three-year reassessment of Long-Term Scenarios, the Commission may decide that identifying or standardizing data inputs and sources may help to ensure that transmission providers are consistently using timely and widely accepted data.[1342] Interwest endorses US DOE's proposal in its comments to the ANOPR to standardize data inputs.[1343] ACORE states that an identification of certain common data sets and modeling best practices will reduce uncertainty, improve transparency, and achieve greater consistency among transmission planning regions.[1344]

611. ENGIE states that data inputs should be sourced from federal and state agencies whenever possible.[1345] Renewable Northwest states that determining a future resource mix for NorthernGrid is possible with publicly available data.[1346] GridLab states that the Commission should consider whether to require that transmission providers either use unadjusted, publicly available data in Long-Term Regional Transmission Planning or justify why using proprietary data would provide superior results.

612. Several commenters state that it is not necessary for the Commission to facilitate the development of data or standardize inputs.[1347] PPL, for example, asserts that the task

[1342] ELCON Initial Comments at 13.

[1343] Interwest Initial Comments at 8 (citing US DOE ANOPR Initial Comments at 12-15).

[1344] ACORE Reply Comments at 5.

[1345] ENGIE Initial Comments at 3.

[1346] Renewable Northwest Initial Comments at 17.

[1347] Ameren Initial Comments at 14-15; Idaho Power Initial Comments at 5;

of developing data inputs should be left to transmission providers, with the caveat that the entire process should avoid hindsight bias or an inappropriate shift in burden or responsibility to the transmission provider.[1348] SPP states that the development of data inputs facilitated by the Commission could provide value if implemented in a way that does not create additional burden to the assessment. SPP suggests that allowing access to recommended data sources or standard information would provide an additional reference for transmission providers to validate their own data, incorporate portions of the data, or utilize all of the data, as appropriate.[1349]

613. US Climate Alliance and US DOE support transparency requirements for data inputs.[1350] Similarly, California Commission and NRECA support transparency requirements for data inputs, subject to appropriate confidentiality considerations.[1351] Colorado Consumer Advocate contends that greater transparency and opportunities for meaningful stakeholder input regarding data inputs for Long-Term Regional

NESCOE Initial Comments at 35-36; New York State Department Initial Comments at 8-9; PPL Initial Comments at 10.

[1348] PPL Initial Comments at 10.

[1349] SPP Initial Comments at 11-12.

[1350] US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 17.

[1351] California Commission Initial Comments at 25; NRECA Initial Comments at 35-37 (citing GDS Associates, Report, at 13 (Aug. 17, 2022)).

Transmission Planning will improve the regional transmission planning process and help to ensure that Order No. 890 transmission planning principles are met.[1352]

614. Concerned Scientists state that the final rule should require transmission providers and load-serving entities to submit to the relevant transmission planner an account of planned investments and retirements over the transmission planning horizon because not doing so ensures a transmission planning process that is less informed than it can and should be. Concerned Scientists state that excluding these minimum requirements from the final rule will inevitably lead to the exclusion of information needed by regulators, stakeholders, and the transmission providers themselves to make informed investment decisions.[1353] PJM, which supports the NOPR proposal, states that, while it is important to consider resource retirements when developing planning assumptions, generation retirement forecasts may be interpreted by stakeholders as sending economic signals concerning the viability of existing generating units. Thus, PJM urges the Commission to provide clear direction on how to balance the heightened transparency and public processes proposed in the NOPR with appropriate safeguards against releasing data that could preempt unit owner economic decisions, as well as decisions by market participants.[1354]

[1352] Colorado Consumer Advocate Initial Comments at 26.

[1353] Concerned Scientists Reply Comments at 17.

[1354] PJM Reply Comments at 22.

615. ITC, PJM, and SEIA support the NOPR proposal, and ITC and SEIA agree with PJM's suggestion that the Commission hold regular forums, workshops, or technical conferences to determine best practices in developing best available data.[1355]

616. SPP Market Monitor contends that the Commission should further provide guidance in the form of parameters by which transmission providers should define the phrase "best available data," which SPP Market Monitor argues would aid in ensuring that the Long-Term Scenarios studied and transmission projects or facilities planned are consistent and reasonable.[1356] Relatedly, Pine Gate states that the NOPR's failure to address source accuracy in the definition of best available date inputs may introduce subjectivity into Long-Term Regional Transmission Planning, obscure sources, and inhibit the ability of stakeholders to meaningfully engage in the Long-Term Regional Transmission Planning process. To remedy these concerns, Pine Gate suggests that the Commission define "best available data inputs" as data inputs that: (1) are current and developed using diverse and expert perspectives expressed during a stakeholder process; (2) have identified sources; (3) are adopted via a process that satisfies Order No. 890's transparency planning principle; and (4) reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios.[1357] Policy Integrity states that the

[1355] ITC Initial Comments at 12; PJM Initial Comments at 76-77; SEIA Initial Comments at 11; SEIA Reply Comments at 4-5.

[1356] SPP Market Monitor Initial Comments at 8.

[1357] Pine Gate Initial Comments at 28.

Commission should require external vetting of data inputs used by a party without a stake in the outcomes.[1358]

617. Several commenters state that the final rule should add a requirement that data must be accurate.[1359] ELCON notes that utilities should consider whether a data source's historical projections ultimately proved to be accurate when identifying "best available" inputs, and Vermont Electric and Vermont Transco agree.[1360] Arizona Commission supports the use of relevant, timely, and accurate data.[1361]

618. LADWP asserts that the determination of "best available data" should be changed to "the most accurate data inputs available" at the time of study because "best" is subjective but "most accurate" is clear and objective. LADWP states that, if data is interpreted differently, as may be the case under the "best available" standard, then results will be inconsistent. For example, LADWP states that the "most accurate data inputs available" for load inputs for near-term planning and for data for generation and energy storage capacities would be data derived from projections based on actual field measurements, and from in-service equipment (instead of from manufacturing brochures or articles), respectively. LADWP states that for new technologies, the projected

[1358] Policy Integrity Initial Comments at 17-18.

[1359] ELCON Initial Comments at 13; LADWP Initial Comments at 4; Vermont Electric and Vermont Transco Initial Comments at 3.

[1360] ELCON Initial Comments at 13; Vermont Electric and Vermont Transco Initial Comments at 3.

[1361] Arizona Commission Initial Comments at 7.

availability and performance parameters should be based on actual data when possible. For example, LADWP states that data derived from field operating experience with prototypes should be considered "most accurate" as compared to lab test data. LADWP contends that transmission providers should be careful not to take "expert perspectives" at face value, but should seek to use data inputs that show a strong correlation to scientifically verifiable facts. Furthermore, LADWP states, projected data based on administrative law or executed interconnection agreements should be considered more certain, and hence more accurate, than data based on corporate or government goals.[1362]

619. GridLab recommends that the Commission request that the national laboratories and other public agencies work with transmission providers, resource developers, and others to evaluate the historical accuracy of publicly available data sources.[1363] However, Ameren sees no reason to expand the definition of best available data inputs to include an evaluation of data source entities' historical accuracy identifying and projecting trends because the open and transparent planning process of diverse stakeholders will identify any questionable or non-reliable data sources.[1364]

620. ELCON states that the Commission may need to clarify what data is considered "timely" and argues, for example, that the Commission should not establish a mandate in favor of using historical data (e.g., actual data from the previous 12 months) because such

[1362] LADWP Initial Comments at 4.

[1363] GridLab Initial Comments at 24.

[1364] Ameren Initial Comments at 15.

data may not reflect current and future operational needs.[1365] Pine Gate is concerned that the use of the term "timely" in the definition of "best available data inputs" may lead to confusion and inconsistency amongst transmission providers.[1366]

621. PJM Market Monitor states that both aggregate and very specific locational data on future demand and the future resource mix will be critical for efficient and cost-effective transmission planning.[1367]

### iii. Concerns with Best Available Data

622. Several commenters either oppose the NOPR proposal or object to specific aspects of the NOPR proposal.[1368] Ameren, EEI, and PPL state that the NOPR proposal is unnecessary and too prescriptive.[1369] Idaho Commission agrees that it is too

[1365] ELCON Initial Comments at 13.

[1366] Pine Gate Initial Comments at 28.

[1367] PJM Market Monitor Initial Comments at 4.

[1368] Ameren Initial Comments at 14-15; Dominion Initial Comments at 26-28; EEI Initial Comments at 14; ELCON Initial Comments at 13; Idaho Power Initial Comments at 5; LADWP Initial Comments at 4; MISO Initial Comments at 40-41; MISO TOs Initial Comments at 18-19; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 35-36; PPL Initial Comments at 9-10; R Street Initial Comments at 7; Vermont Electric and Vermont Transco Initial Comments at 3; Xcel Initial Comments at 10.

[1369] Ameren Initial Comments at 14-15; EEI Initial Comments at 14; PPL Initial Comments at 9.

prescriptive.[1370] EEI states that, while using the best available data inputs when preparing the Long-Term Scenarios is appropriate, a *pro forma* definition may not be necessary.[1371]

623. PPL expresses concern that the proposed requirement for data inputs will unnecessarily burden transmission providers by effectively shifting a burden from data owners (who are in the best position to control and ensure data accuracy) to the transmission provider and instead recommends that the Commission strengthen the requirements applicable to the data owners or data source entities.[1372] Dominion states that using best available data inputs should not be a requirement because transmission providers should be permitted to select the data inputs that are most appropriate for their own situation, as they know their transmission systems best. Dominion additionally does not support defining "best available data inputs" as proposed because it would limit transmission providers' flexibility to conduct transmission planning that is most appropriate to their unique system needs.[1373]

624. MISO, Utah Division of Public Utilities, and Xcel state that the NOPR proposal on data inputs is a potential source of conflict.[1374] MISO is concerned that parties

[1370] Idaho Commission Initial Comments at 3.

[1371] EEI Initial Comments at 14.

[1372] PPL Initial Comments at 9-10.

[1373] Dominion Initial Comments at 26-27.

[1374] MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

opposing particular long-range transmission planning outcomes could seize on the proposed language and argue that some other data was the best available data, thereby delaying the process; and the resulting disputes could potentially slow down the transmission planning process and ultimately delay much needed transmission.[1375] Xcel agrees.[1376] Utah Division of Public Utilities attests that requiring transmission providers to use the best data available is not based on evidence showing that data inputs currently used by transmission providers have led to unjust or discriminatory rates, and may produce unnecessary and time-consuming disagreements among stakeholders regarding which data inputs to use.[1377] National Grid asserts that the term "best available" data is vague and subjective, which introduces development, regulatory and implementation inefficiencies.[1378] Clean Energy Associations argue that transmission providers should be required to explain the number and the basis for including each input they choose to include.[1379]

### iv. Flexibility Issues

625. Several commenters, some that support the NOPR proposal and some that do not, call for flexibility in allowing transmission providers to determine what constitutes best

[1375] MISO Initial Comments at 40.

[1376] Xcel Initial Comments at 10.

[1377] Utah Division of Public Utilities Initial Comments at 6.

[1378] National Grid Initial Comments at 14.

[1379] Clean Energy Associations Initial Comments at 13.

available data. ISO-NE and NYISO support the NOPR proposal but request that the Commission provide transmission providers with some flexibility about how to satisfy this requirement.[1380] ISO-NE asserts that the Commission should allow flexibility for ISO-NE to rely on the states to determine the data inputs, with its technical support and stakeholder input, and NESCOE, which opposes the NOPR proposal, agrees.[1381] NESCOE is concerned about the prescriptive nature of the NOPR proposal and contends that data inputs should be determined on a region-by-region basis by transmission providers with input from states and stakeholders.[1382] MISO agrees on both points.[1383] Duke, which generally supports the NOPR proposal to define best available data inputs and requirement to follow a transparent process to develop the data inputs, states that because there is not a single "best" value for each input, the emphasis should be on best practices to develop the data inputs, which should be left to the regions to develop with their specific stakeholders.[1384]

626. In addition, NYISO requests that the Commission revise the definition of best available data to permit flexibility on how it reflects factors considered in the scenarios. Specifically, NYISO requests that the language in the NOPR specifying that the data

[1380] ISO-NE Initial Comments at 28; NYISO Initial Comments at 28.

[1381] ISO-NE Initial Comments at 28; NESCOE Initial Comments at 35-36.

[1382] NESCOE Initial Comments at 36.

[1383] MISO Initial Comments at 40.

[1384] Duke Initial Comments at 16-17.

inputs must "reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios" should be modified to "reflect the factors that the transmission provider considers in the scenarios" to reflect the authority of transmission planning regions to identify which factors should be used in Long-Term Scenarios. NYISO adds that transmission providers should have authority over how to interpolate and employ their data sets.[1385]

627. MISO, which opposes the NOPR proposal, contends that the Commission should allow transmission providers to determine, in consultation with its stakeholders, what data is most appropriate, but require transmission providers to use the most up-to-date data from the source that they select.[1386] MISO recommends that, if the final rule includes the NOPR proposal for best available data, then the Commission should clarify that transmission providers may satisfy the requirement by using the most up-to-date data that they have selected and that reflects practical limitations regarding the precision and scope of the data.[1387] MISO TOs suggest that the Commission consider articulating principles and guidelines and let transmission planning regions develop their own conception of "best available data" in the interest of flexibility.[1388] Nevada Commission states that the definition of "best available data" may need further comment and will

[1385] NYISO Initial Comments at 28.

[1386] MISO Initial Comments at 40.

[1387] *Id.* at 29.

[1388] MISO TOs Initial Comments at 19.

likely evolve as the Long-Term Regional Transmission Planning process is implemented.[1389]

628. National Grid requests that the Commission clarify that transmission providers have final and sole responsibility and discretion to determine what is "best available data" as transmission providers are best situated to make these determinations in consultation with their stakeholders. National Grid also seeks clarity from the Commission as to what "diverse" means as it describes best available data inputs. National Grid further asserts that the Commission should distinguish between Long-Term Scenarios based on diverse inputs in each scenario.[1390]

### v. Best Sources of Data Issues

629. Several commenters, some that support the NOPR proposal and some that do not, make suggestions about the best sources of data. Several commenters state that transmission providers already have the best available data.[1391] Nebraska Commission further states that the current methods used by RTOs/ISOs would meet the NOPR's proposed requirements.[1392] PPL states that transmission providers already use a "best available data inputs" standard in transmission planning but must rely on other entities'

[1389] Nevada Commission Initial Comments at 9.

[1390] National Grid Initial Comments at 14.

[1391] EEI Initial Comments at 14; Nebraska Commission Initial Comments at 6; PJM Initial Comments at 76; PPL Initial Comments at 9-10.

[1392] Nebraska Commission Initial Comments at 6.

data.[1393] EEI states that, if the Commission adopts a definition for best available data, it should acknowledge that transmission providers and load-serving entities often may possess this data.[1394]

630. Several commenters state that load-serving entities have the best available data.[1395] Eversource recommends that the Commission require the RTOs/ISOs to collaborate with the transmission owners regarding transmission owners' forecast of load localized peak times.[1396] PIOs state that the Commission should require load-serving entities to provide their generation and load forecasts to transmission providers so that they have reasonable information to use and do not have to perform their own estimates.[1397] ACEG and Clean Energy Associations agree.[1398]

631. Western PIOs state that the Western Electricity Coordinating Council databases on load and generation forecasts and the Western Electricity Coordinating Council Anchor dataset constitute best available data.[1399] NARUC argues that any reasonable, credible source of data should be allowed to supplement more traditional sources like the national

[1393] PPL Initial Comments at 9-10.

[1394] EEI Initial Comments at 14.

[1395] *Id.*; Eversource Initial Comments at 20; Xcel Initial Comments at 10.

[1396] Eversource Initial Comments at 20.

[1397] PIOs Initial Comments at 19.

[1398] ACEG Reply Comments at 23; Clean Energy Associations Reply Comments at 7.

[1399] Western PIOs Initial Comments at 31.

laboratories and RTO/ISO-generated data.[1400] SREA recommends that, to the extent possible, the Commission should recognize the National Renewable Energy Lab's Annual Technology Baseline (NREL ATB) as the nation's preferred data set.[1401] Policy Integrity states that the Commission should urge transmission providers to engage independent researchers in the process to ensure inclusion of the latest modeling and computational developments.[1402] PIOs state that the Commission could publish a regularly updated list of databases that meet the "best available data requirement," such as the following current databases: NREL ATB data, US DOE's Annual Energy Outlook for fuel costs, and NREL's Electrification Futures Study for electrification trends. PIOs suggests that the Commission could additionally partner with the US DOE and National Laboratories to develop appropriate databases.[1403]

632. Entergy asserts that integrated resource plans approved by retail commissions should be considered the best available data, and Louisiana Commission and Mississippi Commission agree.[1404] However, Kentucky Commission Chair Chandler disagrees with

[1400] NARUC Initial Comments at 13.

[1401] SREA Reply Comments at 26.

[1402] Policy Integrity Initial Comments at 17.

[1403] PIOs Initial Comments at 19.

[1404] Entergy Initial Comments at 18; Louisiana Commission Reply Comments at 7; Mississippi Commission Reply Comments at 9.

the propositions that local data provided by a utility in an integrated resource plan is superior to other data and that RTOs/ISOs should be required to rely on such data.[1405]

### c. Commission Determination

633. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use "best available data inputs" when developing Long-Term Scenarios. As the Commission explained in the NOPR, by "best available," we do not imply that there is a single "best" value for each data input that transmission providers must use, but rather that best practices will be used to develop each data input. We adopt, with modification, the NOPR proposal to define "best available data inputs" as data inputs that are timely, developed using best practices and diverse and expert perspectives,[1406] and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000.[1407] We further adopt the NOPR proposal to require that best available data inputs also reflect the list of factors that

[1405] Kentucky Commission Chair Chandler Reply Comments at 3.

[1406] While we largely adopt the definition of "best available data inputs" proposed in the NOPR, we modify it to reflect the requirement that "best available data inputs" are developed using best practices.

[1407] For example, the transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

transmission providers account for in their Long-Term Scenarios.[1408] By "reflect the list of factors," we mean the data inputs that correspond to the list of factors that transmission providers have determined might affect Long-Term Transmission Needs.[1409] We also adopt the NOPR proposal to require transmission providers to update, as necessary, all data inputs each time they reassess and revise their Long-Term Scenarios.

634. Finally, in addition, we adopt the NOPR proposal to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process through which transmission providers determine which data inputs to use in their Long-Term Scenarios. Consistent with the coordination transmission planning principle established in Order No. 890, we also adopt the NOPR proposal to require transmission providers in each transmission planning region to give stakeholders an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning which data inputs to use in Long-Term Scenarios.[1410] Also, we clarify that the right to challenge data inputs via dispute resolution as discussed in Order No. 890 is

[1408] One example of a data input dataset that would meet the requirement for best available data are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. Another example of a data input dataset that would meet the requirement for best available data is the most recent data on renewable energy potential and distributed energy resources developed by national labs.

[1409] For example, a transmission provider might determine that corporate goals for corporations less than $20 million are too small to affect Long-Term Transmission Needs and not include these corporate goals in its Long-Term Scenarios. This transmission provider does not have any obligation to develop data inputs corresponding to these omitted corporate goals.

[1410] NOPR, 179 FERC ¶ 61,028 at P 132.

available for interested parties with respect to data inputs that transmission providers develop for Long-Term Regional Transmission Planning.[1411]

635. We agree, in part, with NYISO's suggestion to revise the wording of the NOPR proposal that required best available data to reflect "the list of factors that transmission providers must incorporate into Long-Term Scenarios."[1412] NYISO states that the NOPR language should be modified to "reflect the factors that the public utility transmission provider considers in the scenarios."[1413] As discussed in the Categories of Factors section of this final rule, we explain that transmission providers need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs. We find that transmission providers must use best available data when determining whether each factor is likely to affect Long-Term Transmission Needs. Once transmission providers have determined that a factor is likely to affect Long-Term Transmission Needs, they must use the best available data when they then account for that factor in the development of Long-Term Scenarios.

636. We find that a requirement to use the best available data inputs is warranted to ensure that transmission providers are regularly updating data inputs and using timely and accurate data inputs to inform Long-Term Scenarios. We further find that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, we find that

[1411] Order No. 890, 118 FERC ¶ 61,119 at PP 501-503.

[1412] NYISO Initial Comments at 28 (citing NOPR, 179 FERC ¶ 61,028 at P 131).

[1413] *Id.*

data inputs affect transmission providers' ability to identify Long-Term Transmission Needs and thus affect the ability to identify, evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. We note that many commenters share this view and support the NOPR proposal.[1414]

637. We disagree with commenters asserting that the requirements for data inputs would be overly burdensome to transmission providers.[1415] We believe that, because most transmission providers already endeavor to use best available data inputs to ensure credible results in regional transmission planning, this final rule's requirements for data inputs will not impose an unreasonable burden beyond existing practices today. Further, as many commenters note,[1416] any increase in transmission providers' burden from such

[1414] ACORE Initial Comments at 8; AEE Initial Comments at 22; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17-18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO-NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34-35; NARUC Initial Comments at 13-15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13-14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16-17; US DOE Initial Comments at 16-18; WATT Coalition Initial Comments at 7.

[1415] Ameren Initial Comments at 14; MISO Initial Comments at 29; PPL Initial Comments at 9-10; Utah Division of Public Utilities Initial Comments at 7; Xcel Initial Comments at 10.

[1416] *See* ACORE Initial Comments at 8; AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17-18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO-NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34-35; NARUC Initial Comments at 13-15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13-14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16-17; US DOE

requirements is outweighed by the benefits of establishing reasonable safeguards for accuracy and confidence in Long-Term Regional Transmission Planning.

638. We disagree with commenters' arguments that the final rule requirements for data inputs would lead to problems because stakeholders will delay Long-Term Regional Transmission Planning by contesting the data used by transmission providers.[1417] Similarly, we disagree with commenters' arguments that the requirements for data inputs unnecessarily limit transmission providers' flexibility in producing data inputs.[1418] As discussed above, this final rule establishes requirements for data inputs used in Long-Term Scenarios and requires that stakeholders have an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning those data inputs. However, transmission providers have significant flexibility about which data inputs they use in Long-Term Scenarios, and no commenters have provided us with convincing or specific arguments that stakeholder input will undermine that flexibility or cause consequential delays to the Long-Term Regional Transmission Planning process.

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Initial Comments at 16-18; WATT Coalition Initial Comments at 7.

[1417] MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

[1418] Dominion Initial Comments at 26-27; Duke Initial Comments at 16-17; MISO Initial Comments at 40; MISO TOs Initial Comments at 19; NESCOE Initial Comments at 35-36.

639. We decline to adopt the suggestion of commenters to standardize data inputs used by transmission providers in Long-Term Regional Transmission Planning.[1419] Imposing further requirements to enforce uniformity in data is challenging given regional variation in transmission planning approaches. Further, it might stifle innovation that would improve Long-Term Regional Transmission Planning.

640. We decline to adopt the modifications of the NOPR proposal suggested by certain commenters to establish specific accuracy standards in addition to requiring that transmission providers use best available data inputs.[1420] While we agree that transmission providers should strive for data accuracy, including by assessing the historical accuracy of different data sources where appropriate, a specific accuracy standard would be difficult to develop and administer given the diversity of different data inputs.[1421] As we explain above, transmission providers must use best available data inputs, which include forecasted data, and must develop such inputs using diverse and expert perspectives. They must use best practices to develop data inputs, and must do so

[1419] ACEG Initial Comments at 7; ACORE Initial Comments at 8-9; GridLab Initial Comments at 23; PIOs Initial Comments at 19-20; Southeast PIOs Initial Comments at 47-48.

[1420] ELCON Initial Comments at 13; LADWP Initial Comments at 4; Pine Gate Initial Comments at 27-29; Vermont Electric and Vermont Transco Initial Comments at 3.

[1421] In addition, while we decline to adopt a specific accuracy standard that data must meet in order to be "best available data," we note that a demonstration that a data source has historically proven to be relatively inaccurate would likely constitute evidence that such data is not best available data.

in an open and transparent stakeholder process. Taken together, we believe that these requirements will help ensure that data inputs are as accurate as possible, while also providing transmission providers with the flexibility to use best practices to develop data inputs that are appropriate for their transmission planning regions and to recognize the inherent uncertainty involved in planning transmission on a forward-looking basis.

641. With respect to the issue raised by PJM about revealing potentially confidential data to improve accuracy,[1422] we reiterate, as discussed above, that consistent with Order No. 890's transparency transmission planning principle, transmission providers in each transmission planning region are required to disclose (subject to appropriate confidentiality protections) information and data inputs they use to create each Long-Term Scenario.[1423] The Commission has recognized that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.[1424] The Commission has also noted that using resource-specific data that best reflect actual operations on the transmission system leads to more precise and effective transmission study results. In addition, the Commission has recognized that market participants who provide that information need to be assured that the confidential information they provide will be used for its intended purpose in planning the transmission system and will not be disclosed in a manner that

[1422] PJM Reply Comments at 22.

[1423] *See supra* Number and Development of Long-Term Scenarios section.

[1424] *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227 at P 20.

harms them commercially. However, the Commission has found that, at the same time, the requirement in Order No. 890 for transmission providers to disclose to all customers and other stakeholders the basic methodology, criteria, assumptions, and data that underlie their transmission system plans to enable customers, other stakeholders, or an independent third-party to replicate the results of planning studies is essential to an open and transparent transmission planning process.[1425] Thus, the Commission has found that, without certain generator dispatch and economic information, for example, it becomes difficult or impossible to conduct meaningful load flow studies for some transmission planning purposes,[1426] and the competitive playing field is tilted toward those who have this information and away from those who do not.[1427]

642. The Commission therefore required in Order No. 890, and we apply that requirement to Long-Term Regional Transmission Planning in this final rule, disclosure of the methodology, criteria, assumptions, data and other information that underlie transmission plans, including Long-Term Scenarios. We recognize that no bright line rule exists to determine the appropriate balance between ensuring transparency in the transmission planning processes and ensuring that confidential information is not disclosed inappropriately. Transmission providers may propose what they believe are appropriate confidentiality protections in their filings to comply with this final rule, and

[1425] Order No. 890, 118 FERC ¶ 61,119 at P 471.

[1426] *Id.* P 478.

[1427] *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227 at P 20.

the Commission will evaluate those proposals by using the established principles in Order No. 890, as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

643. With respect to the issue raised by ELCON and Pine Gate about timely data,[1428] we decline to adopt their suggestion to define precisely what "timely" means with respect to best available data because we believe flexibility is warranted given the diverse regional transmission planning processes to which this reform will apply. That is, we believe that updating data inputs may require different timelines depending on the transmission planning region and the specific data input, where each input may change on a different timeline. However, given the five-year duration of the Long-Term Regional Transmission Planning cycle, and the risk of data becoming stale, we require transmission providers to update their data inputs at least once at the outset of each Long-Term Regional Transmission Planning cycle.

644. With respect to National Grid's request to clarify the definition of "diverse" in the context of the requirement that data inputs must be developed using diverse and expert perspectives,[1429] we clarify that the term "diverse" specifically used in the context of data inputs indicates that the data inputs must represent a range of data within the bounds of plausibility. We believe that this requirement will ensure that the *set* of Long-Term

[1428] ELCON Initial Comments at 13; Pine Gate Initial Comments at 28-29.

[1429] National Grid Initial Comments at 14.

Scenarios that are developed from these data inputs will represent a reasonable range of probable future outcomes consistent with the requirement for plausibility.

### 8. Identification of Geographic Zones

#### a. NOPR Proposal

645. In the NOPR, the Commission proposed to require that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. If transmission providers within a transmission planning region choose to establish geographic zones, then the Commission proposed to require the transmission provider to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.[1430]

646. The Commission preliminarily found that requiring the consideration and potential identification of geographic zones within Long-Term Scenarios assists transmission providers, transmission developers, and generation developers in coordinating their activities. The Commission stated that transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by

[1430] NOPR, 179 FERC ¶ 61,028 at P 145.

considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest. Further, the Commission stated that, using the information gained through the process described below to identify such geographic zones, transmission providers in each transmission planning region could then plan transmission facilities that would serve large concentrations of new generation in a more efficient or cost-effective manner.[1431]

647. The Commission proposed to require, as step one of the three-step geographic zone process, that transmission providers consider whether to establish and include in the regional transmission planning process outlined in their OATTs the method that they will use to identify geographic zones within the transmission planning region. The Commission also proposed to require that transmission providers in each transmission planning region use this information to create a set of draft geographic zones, and that they post on their OASIS or other public website maps of the draft geographic zones, as well as the information used to create the draft geographic zones, for stakeholders' input.[1432]

648. In addition, the Commission proposed to require transmission providers in each transmission planning region to consider this stakeholder feedback and modify the draft

[1431] *Id.* P 146.

[1432] *Id.* PP 147-148.

geographic zones as appropriate to produce a final list of designated geographic zones within the transmission planning region.[1433]

649. The Commission proposed to require, in step two of the three-step geographic zone process, that transmission providers in each transmission planning region assess generation developers' commercial interest in developing generation within each designated geographic zone.[1434] The Commission proposed to require, in the final step of the three-step geographic zone process, that transmission providers in each transmission planning region incorporate the information from step one and step two regarding the designated geographic zones into their Long-Term Scenarios.[1435]

**b. Comments**

650. Many commenters support the Commission's proposal to require each transmission provider, as part of its regional transmission planning process, to consider whether to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones,

[1433] The Commission noted that, while it referred to multiple "zones," subsequent to stakeholder feedback, the final list may contain only one designated geographic zone. *Id.* P 149.

[1434] *Id.* P 150.

[1435] *Id.* P 151.

and the identified commercial interest in each zone, into Long-Term Scenarios.[1436] Commenters assert that, compared to interconnection-related network upgrades identified on a case-by-case basis in the interconnection process, identifying and incorporating geographic zones into Long-Term Scenarios would save consumers money by identifying more efficient or cost-effective transmission facilities to connect areas with the potential for low cost generation to load centers and reduce congestion and generator curtailment.[1437] Further, commenters note the success of previous planning efforts in ERCOT, MISO, CAISO, and ISO-NE to incorporate geographic zones into their transmission planning efforts.[1438]

651. Some commenters highlight the importance of this proposed reform for remotely located renewable resources generally, and more specifically for offshore wind, which is

[1436] Ameren Initial Comments at 15; American Municipal Power Initial Comments at 35; Clean Energy Associations Initial Comments at 13; EEI Initial Comments at 15; ENGIE Initial Comments at 4; Eversource Initial Comments at 21-22; Interwest Reply Comments at 4; ISO-NE Initial Comments at 30; ITC Initial Comments at 5, 13-17; Middle River Power Initial Comments at 3; MISO Initial Comments at 30; NARUC Initial Comments at 16; Nebraska Commission Initial Comments at 6-7; NESCOE Initial Comments at 37; New Jersey Commission Initial Comments at 15; New York TOs Initial Comments at 12; New York Transco Initial Comments at 5-6; Northwest and Intermountain Initial Comments at 5-6; NRECA Initial Comments at 37; New York Commission and NYSERDA Initial Comments at 14-15; NYISO Initial Comments at 29-30; Ørsted Initial Comments at 7; US DOE Initial Comments at 18; Western PIOs Initial Comments at 31-32.

[1437] *See*, *e.g.*, ENGIE Initial Comments at 4; Eversource Initial Comments at 21-22; ITC Initial Comments at 13-17; Northwest and Intermountain Initial Comments at 5-6; NYISO Initial Comments at 29-30.

[1438] *See*, *e.g.*, ENGIE Initial Comments at 4; Eversource Initial Comments at 21-22.

constrained to lease areas auctioned by the Bureau of Ocean Energy Management.[1439] For example, Ørsted argues that the location and approximate resource potential of offshore wind is well understood and the failure to proactively plan the necessary transmission would result in higher costs to ratepayers.[1440] BP further contends that the geographic zones in which National Interest Electric Transmission Corridors are likely to be established also merit inclusion in transmission planning.[1441]

652. Some commenters support the proposal but urge the Commission to *require* the identification of geographic zones and planning transmission to integrate generation in those zones rather than just requiring transmission providers to *consider* whether to identify geographic zones.[1442] Acadia Center and CLF argue that the Commission should require the identification and creation of geographic zones in areas where the majority of states have binding greenhouse gas emission reduction or renewables mandates, which could result in fewer transmission corridors being built, thereby reducing costs, siting

[1439] *See, e.g.*, BP Initial Comments at 4, 7-8; Clean Energy Buyers Initial Comments at 18; New York Transco Initial Comments at 5-6; Ørsted Initial Comments at 7-8.

[1440] *See, e.g.*, Ørsted Initial Comments at 7-8.

[1441] BP Initial Comments at 7 (citing 16 U.S.C. 824p).

[1442] Acadia Center and CLF Initial Comments at 13-15; Amazon Initial Comments at 6-7; California Water Initial Comments at 16; Center for Biological Diversity Initial Comments at 13-15; City of New York Initial Comments at 7-8; Handy Law Initial Comments at 12; Invenergy Reply Comments at 9-10; SEIA Initial Comments at 11-12; Shell Initial Comments at 23.

challenges, and benthic environmental impacts.[1443] Acadia Center and CLF assert that, without mandatory identification and establishment of geographic zones, there is a significant risk that adequate transmission will not be built to accommodate state emission reduction and renewables mandates in a cost-effective or efficient way.[1444]

653. In contrast, other commenters emphasize that they support the proposal to require transmission providers to *consider* identifying geographic zones rather than to actually identify such geographic zones.[1445] Such commenters assert that providing the option to identify geographic zones would allow transmission providers to determine, with their stakeholders, what is right for their transmission planning region.[1446]

654. Other commenters express concerns with the idea of incorporating geographic zones with the potential for large amounts of generation into regional transmission planning, but do not oppose the proposal so long as it is optional.[1447] For example,

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[1443] Acadia Center and CLF Initial Comments at 13-14.

[1444] *Id.* at 13.

[1445] *See, e.g.*, Ameren Initial Comments at 15-16; American Municipal Power Initial Comments at 34-35; Clean Energy Associations Initial Comments at 13; EEI Initial Comments at 15; ISO-NE Initial Comments at 30; ITC Initial Comments at 5, 13-17; MISO Initial Comments at 30; Nebraska Commission Initial Comments at 6-7; NESCOE Initial Comments at 37; NRECA Initial Comments at 37; New York Commission and NYSERDA Initial Comments at 14-15; NYISO Initial Comments at 32; PPL Initial Comments at 11; US Chamber of Commerce Initial Comments at 7.

[1446] *See, e.g.*, EEI Initial Comments at 15; ISO-NE Initial Comments at 30; MISO Initial Comments at 30; New York Commission and NYSERDA Initial Comments at 14-15; NYISO Initial Comments at 32.

[1447] APPA Initial Comments at 29-30; Dominion Initial Comments at 28-29; Georgia Commission Initial Comments at 6; Large Public Power Initial Comments at 22;

NESCOE and National Grid assert that the proposed requirements for each of the three steps is overly prescriptive and could be included in a final rule as guidance, but not as a mandate.[1448]

655. Several commenters urge the Commission to provide flexibility in any process for considering and potentially identifying geographic zones.[1449] For example, Michigan Commission states that the proposed three-step process in the NOPR is highly prescriptive and overly burdensome, and instead the Commission should provide greater flexibility to ensure that generation siting assumptions included in Long-Term Scenarios are developed transparently in collaboration with state regulators, generation utilities, and resource planners.[1450]

656. Several commenters suggest modifications to the NOPR proposal.[1451] For example, Vistra contends that the NOPR proposal could be improved through the use of

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National Grid Initial Comments at 16-17; NESCOE Initial Comments at 38; SERTP Sponsors Initial Comments at 27; SPP Market Monitor Initial Comments at 11-12; TANC Initial Comments at 10.

[1448] NESCOE Initial Comments at 38; National Grid Initial Comments at 16.

[1449] *See, e.g.*, APS Initial Comments at 5; ISO-NE Initial Comments at 30; Michigan Commission Initial Comments at 6; MISO Initial Comments at 42; MISO TOs Initial Comments at 32; NARUC Initial Comments at 17; New Jersey Commission Initial Comments at 15; NYISO Initial Comments at 3-4.

[1450] Michigan Commission Initial Comments at 6.

[1451] Acadia Center and CLF Initial Comments at 15-16; California Energy Commission Initial Comments at 2-3; Center for Biological Diversity Initial Comments at 13-16; Clean Energy Associations Initial Comments at 24-25; Illinois Commission Initial Comments at 9-11; Large Public Power Initial Comments at 26; Microgrid Resources Coalition Initial Comments at 4-6; New Jersey Commission Initial Comments

open seasons or other comparable tools to elicit concrete commitments from generator developers.[1452] Other commenters argue that the NOPR proposal should be modified to involve a subscription model in which prospective generation resources within the zone indicate their willingness to pay for transmission to the zone.[1453] Although PJM opposes the NOPR proposal, PJM argues that these alternative proposals offered by Vistra and New Jersey Commission have merit and are worthy of further dialogue.[1454]

657. Regarding the specific steps in the NOPR proposal for identifying geographic zones, several commenters support the proposal to provide all stakeholders, including relevant federal and state siting authorities, with a meaningful opportunity to provide input on the draft geographic zones.[1455] Other commenters, however, assert that the Commission should provide a clearer role for states and other stakeholders to participate earlier in the process of identifying geographic zones.[1456]

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at 16-17; Vistra Initial Comments at 24.

[1452] Vistra Initial Comments at 24.

[1453] Clean Energy Associations Initial Comments at 24-25; Large Public Power Initial Comments at 26; New Jersey Commission Initial Comments at 16-17.

[1454] PJM Reply Comments at 29-30, 31-32.

[1455] ISO/RTO Council Initial Comments at 8; NARUC Initial Comments at 16-17; National Grid Initial Comments at 17; Nebraska Commission Initial Comments at 7; SEIA Initial Comments at 12-13; Shell Initial Comments at 25.

[1456] Acadia Center and CLF Initial Comments at 12-13; AEE Initial Comments at 24-25; Amazon Initial Comments at 7; CAISO Initial Comments at 4-5, 28-29, 31; DC and MD Offices of People's Counsel Initial Comments at 15-16; Interwest Initial Comments at 9; ISO-NE Initial Comments at 29; National Grid Initial Comments at 17-18; NESCOE Initial Comments at 38-39; Nevada Commission Initial Comments at 9-10;

658. Some commenters argue that the NOPR proposal regarding what information transmission providers should use to gauge commercial interest in geographic zones is overly prescriptive and that the information would be too speculative to be an accurate indicator of commercial interest.[1457] Several commenters urge the Commission to increase the transparency of the NOPR proposal.[1458] For example, US DOE recommends that the Commission specify minimum standards for reporting the attributes of each geographic zone.[1459]

659. Several commenters oppose the proposal to require transmission providers to consider whether to identify geographic zones with the potential for large amounts of generation.[1460] For example, APS argues that the proposal may not be appropriate due to the speculative nature of the identification of geographic zones and the long-term nature

SERTP Sponsors Initial Comments at 27.

[1457] *See*, *e.g.*, Middle River Power Initial Comments at 3; MISO Initial Comments at 43; PJM Initial Comments at 84.

[1458] Amazon Initial Comments at 8; Shell Initial Comments at 23-24; US DOE Initial Comments at 24-25

[1459] US DOE Initial Comments at 20.

[1460] APS Initial Comments at 5-7; Arizona Commission Initial Comments at 8; CAISO Initial Comments at 27-28; Consumer Organizations Initial Comments at 3-7; Duke Initial Comments at 4, 18-19; Idaho Power Initial Comments at 5; Indicated PJM TOs Initial Comments at 3-4, 12-13; ISO/RTO Council Initial Comments at 7; LADWP Initial Comments at 4; Louisiana Commission Initial Comments at 24-25; Michigan Commission Initial Comments at 5-6; Microgrid Resources Initial Comments at 5; North Carolina Commission and Staff Initial Comments at 8-10; North Dakota Commission Initial Comments at 4-5; Ohio Commission Federal Advocate Initial Comments at 7-8.

of planning and building transmission infrastructure.[1461] Idaho Power is concerned that the NOPR proposal will create a significant level of work for transmission providers that would outweigh the minor benefits developers would receive from the data.[1462]

660. PJM opposes the NOPR proposal, which it describes as an arbitrary and inflexible process that fails to account for regional differences and that will require transmission providers to draw lines on a map and commit to these areas for 20 years.[1463] PJM states that the information from the geographic zones will be poor compared to information in the marketplace, including nearer term decisions of interconnection customers.[1464] PJM states that an alternative, more case-specific flexible approach that builds on and is better synchronized with the transmission provider's interconnection queue process and market developments, and accommodates topologies as diverse as those in PJM, is a better solution.[1465] For example, PJM suggests that the PJM State Agreement Approach is a better way to facilitate clusters of renewable energy interconnections by finding states that are willing to sponsor the new transmission to help fulfill a renewable energy policy.[1466]

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[1461] APS Initial Comments at 6-7.

[1462] Idaho Power Initial Comments at 5.

[1463] PJM Initial Comments at 77-78.

[1464] *Id.* at 77.

[1465] *Id.* at 7.

[1466] *Id.* at 79-82 (citing PJM Operating Agreement, Schedule 6, section 1.5.9).

661. Several state commissions express concerns that the NOPR proposal would give undue preference to certain kinds of resources.[1467] For example, North Dakota Commission argues that the NOPR proposal would bias transmission planning towards one type of generation, encourage speculative build-out of transmission, and prevent visibility into the cost of other generation/transmission combinations, which will result in under-utilized transmission and additional costs to ratepayers with little benefit.[1468]

662. North Carolina Commission and Staff assert that the NOPR proposal is an unwarranted intrusion into state jurisdiction over generation and fails to acknowledge state authority over utility generation, resource portfolios, and integrated resource planning.[1469] Similarly, Ohio Commission Federal Advocate asserts that the NOPR proposal exceeds the Commission's authority and interferes with Ohio's ability to maintain its competitive retail electric service law.[1470] Mississippi Commission states that decisions to develop such zones within a state should be left to the state.[1471]

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[1467] Arizona Commission Initial Comments at 8; Louisiana Commission Initial Comments at 24-25; Louisiana Commission Reply Comments at 11-12; Michigan Commission Initial Comments at 5-6; North Carolina Commission and Staff Initial Comments at 10-13; North Dakota Commission Initial Comments at 4; Ohio Commission Federal Advocate Initial Comments at 7-8; Pennsylvania Commission Initial Comments at 7-8.

[1468] North Dakota Commission Initial Comments at 4.

[1469] North Carolina Commission and Staff Initial Comments at 8.

[1470] Ohio Commission Federal Advocate Initial Comments at 7 (quoting Ohio Commission Federal Advocate ANOPR Comments at 8).

[1471] Mississippi Commission Reply Comments at 10.

Pennsylvania Commission argues that the geographic zones used for Long-Term Scenarios could frustrate a state's legitimate policy choices in establishing, for example, economic development zones designed to encourage developers to site generation in specific areas, by favoring another state's policy choices.[1472] TAPS opposes any requirement to undertake a process to consider and identify remote geographic zones where state or local laws require local generating resources rather than remote resources.[1473]

663. Many commenters argue that the NOPR proposal would be duplicative of, or would interfere with, existing processes.[1474] AEE states that the consideration of geography in developing long-term regional transmission plans should occur as a natural outgrowth of more effective regional transmission planning and that a specific requirement to identify geographic zones could have unintended consequences.[1475] AEE further asserts that some of the factors that the NOPR proposes to require transmission

[1472] Pennsylvania Commission Initial Comments at 7-8.

[1473] TAPS Initial Comments 9-10.

[1474] AEE Initial Comments at 8; APS Initial Comments at 5; CAISO Initial Comments at 4-5; Duke Initial Comments at 18-19; Illinois Commission Initial Comments at 9-11; Indicated PJM TOs Initial Comments at 12; ISO-NE Initial Comments at 30; ISO/RTO Council Initial Comments at 7; MISO TOs Initial Comments at 32; Mississippi Commission Reply Comments at 10; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12-13; TAPS Initial Comments 8-10; Xcel Initial Comments at 10-11.

[1475] AEE Initial Comments at 8.

providers to incorporate in their Long-Term Scenarios inherently require them to consider what geographic areas are ripe for low-cost generation development but are isolated or otherwise transmission constrained.[1476] Similarly, Indicated PJM TOs argue that it is unnecessary to require the identification of geographic zones in Long-Term Regional Transmission Planning because transmission providers necessarily will rely on driving factors (e.g., public policy goals) that will determine where renewable resources will be developed.[1477] According to Duke, the categories of factors proposed in the NOPR already capture generator interconnections, so it is unclear what this additional process will add.[1478]

664. Several commenters argue that some transmission planning processes already incorporate the identification of geographic zones, and those existing processes should be allowed to continue.[1479] ISO-NE claims that transmission providers' planning constructs may already include rules that allow for assessing and identifying geographic zones with potential for high renewable development, rendering a separate process redundant or

[1476] *Id.* at 23-24.

[1477] Indicated PJM TOs Initial Comments at 12.

[1478] Duke Initial Comments at 18.

[1479] *See, e.g.*, CAISO Initial Comments at 27-33; ISO-NE Initial Comments at 30; MISO TOs Initial Comments at 32; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12-13.

unnecessary.[1480] SPP states that the NOPR proposal would duplicate SPP's current process to some extent and that it would not be practical to do both.[1481] Similarly, CAISO argues that the NOPR proposal is overly prescriptive and would interfere with California's existing processes, which are working effectively.[1482] New York TOs note that New York's transmission planning processes already include the evaluation of geographic zones expected to see significant growth in generation or changes in load and incorporate state involvement.[1483] Mississippi Commission asserts that MISO already considers geographic zones for new generation.[1484]

### c. Commission Determination

665. We decline to adopt the proposed requirement that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. We are persuaded by commenters that finalizing and requiring the NOPR proposal is not warranted at this time. Further, given the other requirements in this final rule, such as the requirement for transmission providers to plan for factors affecting supply and demand, we agree with commenters that

[1480] ISO-NE Initial Comments at 30.

[1481] SPP Initial Comments at 12-13.

[1482] CAISO Initial Comments at 4-5, 27-33.

[1483] New York TOs Initial Comments at 12.

[1484] Mississippi Commission Reply Comments at 10.

adopting this proposed requirement is not necessary at this time to ensure that Long-Term Regional Transmission Planning ensures just and reasonable rates. We also agree with commenters that the prescriptive nature of the proposed three-step process could unintentionally impede existing efforts to incorporate geographic zones into regional transmission planning.

666. Although we are not adopting the NOPR proposal, we encourage transmission providers to consider geographic zones that have the potential for development of large amounts of new generation as part of their regional transmission planning process. As such, transmission providers in a transmission planning region may propose to identify geographic zones as part of Long-Term Regional Transmission Planning on compliance with this final rule, provided that they demonstrate that their process for identifying such geographic zones is consistent with or superior to the Long-Term Regional Transmission Planning requirements established herein.

### D. Evaluation of the Benefits of Regional Transmission Facilities

667. In this final rule, we require transmission providers, as part of Long-Term Regional Transmission Planning, to measure seven specified benefits that were enumerated in the NOPR ("set of seven required benefits" or "required benefits") in each Long-Term Scenario. We also allow transmission providers to propose on compliance to measure additional benefits as part of Long-Term Regional Transmission Planning. In addition, we require transmission providers to use those measured benefits when

evaluating Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs.[1485]

668. This section of the final rule discusses the requirements that we adopt governing transmission providers' measurement and use of benefits in Long-Term Regional Transmission Planning. Specifically, we discuss: (1) the requirement to use a set of seven required benefits; (2) the required benefits, themselves; (3) the requirement to include a general description of how transmission providers will measure each of the benefits that the final rule requires, as well as any additional benefits that they may propose, in their OATTs; (4) the requirements related to the minimum time horizon over which transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities; (5) the evaluation of the benefits of portfolios of Long-Term Regional Transmission Facilities; and (6) other issues related to benefits.

### 1. Requirement for Transmission Providers to Use a Set of Seven Required Benefits

#### a. NOPR Proposal

669. In the NOPR, the Commission proposed a list of benefits that transmission providers in each transmission planning region may consider in Long-Term Regional Transmission Planning and cost allocation processes, which included: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either

[1485] As discussed in the Development of Long-Term Scenarios section *supra*, transmission providers must also use these benefits to inform their identification of Long-Term Transmission Needs.

reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[1486] The NOPR provided a description of each of these benefits categories as well as a method to calculate benefits in each category.[1487]

670. The Commission explained that it was not proposing to make the list of potential benefits mandatory or exhaustive and that transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.[1488]

671. The 12 potential benefits described in the NOPR are:

| No. | Benefit | Description |
|---|---|---|
| 1 | Avoided or deferred reliability transmission | Reduced costs of avoided or delayed transmission investment otherwise required to |

[1486] NOPR, 179 FERC ¶ 61,028 at P 185. As more fully described below, the Commission is making modifications to the list of benefits in this final rule. Therefore, we clarify for the reader how we refer to each of those benefits in this section. We refer to benefits 1-6 as "Benefit 1," "Benefit 2," etc. We refer to Benefit 7, "mitigation of weather and load uncertainty" as NOPR Benefit 7. We refer to "(8) capacity cost benefits from reduced peak energy losses" as "NOPR Benefit 8", "Final Rule Benefit 7", and "Benefit 7". We refer to benefits 9-12 as "Benefit 9," Benefit 10," etc.

[1487] *Id.* PP 189-225.

[1488] *Id.* P 184.

| | | |
|---|---|---|
| | facilities and aging transmission infrastructure replacement | address reliability needs or replace aging transmission facilities |
| 2a | Reduced loss of load probability<br>[OR next benefit] | Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load |
| 2b | Reduced planning reserve margin<br>[OR prior benefit] | While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements |
| 3 | Production cost savings | Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also, reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings |
| 4 | Reduced transmission energy losses | Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand |
| 5 | Reduced congestion due to transmission outages | Reduced production costs during transmission outages that significantly increase transmission congestion |
| 6 | Mitigation of extreme events and system contingencies | Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system |
| 7 | Mitigation of weather and load uncertainty | Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns |

| | | |
|---|---|---|
| 8 | Capacity cost benefits from reduced peak energy losses | Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses |
| 9 | Deferred generation capacity investments | Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas |
| 10 | Access to lower-cost generation | Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources) |
| 11 | Increased competition | Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power |
| 12 | Increased market liquidity | Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for Long-Term Regional Transmission Planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion |

672. While the Commission did not propose to require use of any specific benefits in the NOPR, it sought comment on whether transmission providers should be required to use some or all of the potential benefits described in the NOPR as a minimum set of benefits for their Long-Term Regional Transmission Planning process.[1489]

[1489] *Id.* P 188.

**b. Comments**

673. Many commenters support the NOPR approach of providing illustrative benefits rather than mandating the use of certain benefits.[1490] Indicated PJM TOs contend that the NOPR proposal would advance the Commission's goals better than a more prescriptive proposal.[1491] SERTP Sponsors and Southern argue that the Commission should not impose a minimum set of benefits because existing state-regulated integrated resource planning processes adequately examine some of the proposed benefits, and that some of the proposed benefits would harm existing integrated resource planning processes or are only appropriate for RTO/ISO regions.[1492] LADWP asserts that some or all of the

[1490] Ameren Initial Comments at 19; APPA Initial Comments at 31; APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22-23; EEI Initial Comments at 19-20; Eversource Initial Comments at 25; Georgia Commission Initial Comments at 6-7; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7-8; Illinois Commission Initial Comments at 13-14; Indiana Commission Initial Comments at 6; Indicated PJM TOs Initial Comments at 17; ISO-NE Initial Comments at 5, 33-34; LADWP Initial Comments at 5; Louisiana Commission Reply Comments at 9-10; Michigan Commission Initial Comments at 6; MISO Initial Comments at 9, 51-52; Mississippi Commission Initial Comments at 36; NARUC Initial Comments at 20-21; National Grid Initial Comments at 26; North Carolina Commission and Staff Initial Comments at 7; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; NRECA Initial Comments at 43-45; NYISO Initial Comments at 9, 37-38; OMS Initial Comments at 7-8; Pacific Northwest Utilities Initial Comments at 8; Pennsylvania Commission Initial Comments at 9; SERTP Sponsors Initial Comments 29-30; Southern Initial Comments at 24; TANC Initial Comments at 16; TAPS Initial Comments at 3, 14; US Chamber of Commerce Initial Comments at 7; Vermont State Entities Initial Comments at 7; Virginia Commission Staff Initial Comments at 5; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

[1491] Indicated PJM TOs Initial Comments at 17.

[1492] SERTP Sponsors Initial Comments 29-30; Southern Initial Comments at 25-27.

identified benefits will be considered as part of the normal transmission planning process without a requirement. [1493] Dominion asserts that the question arises of who will judge whether a transmission project addresses the NOPR's proposed list of benefits and that such debates could be time-consuming and further delay projects and drive up costs.[1494] Dominion states that transmission providers should be permitted to identify the benefits that they will consider in conducting Long-Term Regional Transmission Planning but retain flexibility to apply the specific benefits that are most appropriate given each transmission provider's individual circumstances.[1495]

674. TAPS supports requiring transmission providers to evaluate production cost modeling but opposes requiring transmission providers to consider any other benefits in order to allow for regional flexibility.[1496] Northwest and Intermountain and NYISO ask that the final rule confirm that the 12 illustrative benefits are neither mandatory nor exhaustive.[1497] California Municipal Utilities state that requiring the consideration of all 12 benefits proposed in the NOPR would misapprehend the state and local nature of resource portfolio planning and fail to account for the costs of such prescriptive measures

[1493] LADWP Initial Comments at 5.

[1494] Dominion Initial Comments at 34.

[1495] *Id.*

[1496] TAPS Initial Comments at 3, 14.

[1497] Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

and the need for consumer protection measures to guard against speculative transmission projects.[1498]

675. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.[1499] Relatedly, Xcel states that for any specific study, portfolio, or transmission project, all benefits do not need to be calculated and, in some cases, calculating additional benefits may be costly, time consuming, and contentious and provide little added value.[1500]

676. Many of the commenters that support an illustrative approach emphasize the importance of regional flexibility.[1501] US Chamber of Commerce states that flexibility will allow transmission planning regions to consider benefits that best align with their

[1498] California Municipal Utilities Reply Comments at 5-6.

[1499] OMS Initial Comments at 8.

[1500] Xcel Initial Comments at 12.

[1501] Ameren Reply Comments at 16-17 (citing MISO Initial Comments at 9); APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22-23; EEI Initial Comments at 19-20; Eversource Initial Comments at 25; Entergy Reply Comments at 3; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7-8; Illinois Commission Initial Comments at 13-14; Indiana Commission Initial Comments at 6-7; Large Public Power Initial Comments at 28; ISO-NE Initial Comments at 33-34; Massachusetts Attorney General Initial Comments at 12, 15; MISO Initial Comments at 9; Mississippi Commission Initial Comments at 35-36; NARUC Initial Comments at 20-21; National Grid Initial Comments at 26; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9; SPP Initial Comments at 18; US Chamber of Commerce Initial Comments at 7; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

respective market structures.[1502] MISO states that, without flexibility, it may not be able to move forward with the transmission projects of the greatest benefit and value to MISO and its stakeholders, noting that benefits used to meet criteria for its recent Long-Range Transmission Planning projects are not specified in its OATT.[1503] MISO, NYISO, and SPP argue that transmission providers and their stakeholders ought to determine what the benefits evaluated for specific transmission projects or sets of projects should be.[1504] NARUC, New York TOs, and Pennsylvania Commission agree, emphasizing consultation with states.[1505]

677. Entergy urges the Commission to affirm its commitment to providing transmission planning regions with flexibility in terms of how they identify, consider, and calculate benefits. Entergy further urges the Commission to adopt guiding principles to aid transmission providers in identifying their own benefits.[1506] Entergy argues that the Commission should recognize that not all benefits are appropriate in all jurisdictions and

[1502] US Chamber of Commerce Initial Comments at 7.

[1503] MISO Initial Comments at 9.

[1504] MISO Initial Comments at 9-10; NYISO Initial Comments at 39; SPP Initial Comments at 18.

[1505] NARUC Initial Comments at 21-22; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9.

[1506] Entergy Initial Comments at 21.

that some states will want to prioritize transmission projects that reduce customer bills.[1507]

678. SPP argues that how and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each transmission provider and its stakeholders. Specifically, SPP argues that the effort required to incorporate additional benefit metrics into its current transmission planning process cannot be accommodated within its current process timeline.[1508]

679. Mississippi Commission argues that any required benefits would be arbitrary and some metrics may not be applicable at times.[1509] National Grid argues that flexibility will allow transmission providers to adapt more readily to changes in state policy drivers, prevent the requirements of Long-Term Regional Transmission Planning from becoming dated, and allow benefits and cost allocation discussions to be synchronized.[1510] Duke contends that allowing regional flexibility may help to mitigate some disputes within transmission planning regions over what benefits to measure and how to measure them. Moreover, Duke argues that regional flexibility is critical to ensuring that each benefit metric used is relevant and calculable for each transmission planning region, particularly given differences between RTO/ISO and non-RTO/ISO regions. Duke contends that

[1507] *Id.*

[1508] SPP Initial Comments at 18.

[1509] Mississippi Commission Initial Comments at 35-36.

[1510] National Grid Initial Comments at 26-27.

regions must not be forced into accepting and implementing benefits metrics that they have not vetted or on which they do not have consensus.[1511]

680. MISO, while stating its preference for flexibility in identifying benefits, also states that it would support identifying and using a general set of benefit metrics that capture key areas of transmission value, such as reliability and resilience, production cost savings, and avoided resource and/or transmission investment, assuming that each transmission planning region may determine how to calculate each metric and how each applies during a transmission assessment, as well as allowing for different benefit metrics not part of that "general set" to be applied when warranted.[1512]

681. Some commenters offer support for the illustrative benefits without suggesting that they be required.[1513] PG&E states that CAISO's transmission planning process currently evaluates several of the same benefits, either routinely or on a case-specific basis, and that PG&E supports the continued flexibility the NOPR envisions for RTO/ISOs.[1514]

682. In contrast, many commenters support the Commission requiring that transmission providers consider a minimum list of benefits for Long-Term Regional Transmission

[1511] Duke Initial Comments at 22-23.

[1512] MISO Initial Comments at 9.

[1513] Nevada Commission Initial Comments at 10-11; Pattern Energy Initial Comments at 14; PG&E Initial Comments at 7.

[1514] PG&E Initial Comments at 7.

Planning.[1515] PIOs argue that most of the benefits outlined in the NOPR have broad support, even among those commenters that do not support a Commission requirement to consider a minimum set of benefits.[1516]

683. Clean Energy Associations and US Senator Schumer assert that the failure to adopt a minimum list of benefits risks skewing benefit-to-cost ratios against developing necessary transmission because all costs would be included in an evaluation but not all benefits would also be included.[1517] Clean Energy Associations further state that failing

[1515] ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at 6, 23-25; Breakthrough Energy Initial Comments at 4, 21-22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11-12; Clean Energy Buyers Reply Comments at 8-9; Concerned Scientists Reply Comments at 7-10; Cypress Creek Reply Comments at 7-8; DC and MD Offices of People's Counsels Reply Comments at 3, 7-8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16: Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18-22; Interwest Initial Comments at 12; Interwest Reply Comments at 6-7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11-14; Pacific Northwest State Agencies Initial Comments at 16-17; PIOs Initial Comments at 27-28; PIOs Reply Comments at 7-8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16-17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27-28; US DOE Initial Comments at 30-33; US Senator Schumer Supplemental Comments at 1-2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

[1516] PIOs Initial Comments at 26, 41; PIOs Reply Comments at 7-8.

[1517] Clean Energy Associations Initial Comments at 19; US Senator Schumer

to require the adoption of a minimum list of benefits could lead to higher costs in the long-term, as larger transmission projects with net benefits would not be selected.[1518] Finally, Clean Energy Associations argue that, without a minimum list of benefits, significant disparities in regional identification of potential Long-Term Regional Transmission Facilities could have harmful spillover effects on coordinated activities such as interregional transmission coordination and affected systems studies.[1519]

684. Michigan State Entities argue that there must be some prescribed list of benefits, asserting that it would not force differently situated transmission providers to implement any specific policy, but instead would ensure that they take a "fair look" at transmission planning policies, including those using storage, that could produce substantial savings for customers.[1520] Interwest contends that a standard and comprehensive framework for evaluating benefits is necessary because an ad hoc approach could result in inconsistencies and an incomplete picture of a transmission project's potential benefits.[1521]

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Supplemental Comments at 1-2.

[1518] Clean Energy Associations Initial Comments at 19-20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses*, at 26 (Apr. 2021)).

[1519] Clean Energy Associations Initial Comments at 19.

[1520] Michigan State Entities Reply Comments at 2.

[1521] Interwest Reply Comments at 7.

685. Southeast PIOs urge the Commission to prescribe a set of benefits for use in benefit-cost analyses, starting with the entire list of benefits in the NOPR. Southeast PIOs argue that the transmission providers in the Southeast exploited the flexibility in establishing and assessing benefits that the Commission provided in Order No. 1000 to implement a straight cost comparison.[1522] Southeast PIOs further state that minimum standards are necessary to produce actionable results; otherwise, Long-Term Regional Transmission Planning will devolve into a "box-checking exercise."[1523] SREA argues that the Commission needs to set clear guidelines around benefit metrics to avoid opponents to the NOPR finding easy work-arounds.[1524]

686. Similarly, R Street states that transmission providers should be required to use a minimum set of benefits because they lack the incentive to account for all system-wide benefits. R Street argues that proposing a benefits list for transmission providers to consider is the status quo and the Commission should expect little change without a benefits requirement.[1525] Concerned Scientists agree, claiming that the experience with Order No. 1000 implementation and the descriptions in the comments in response to the NOPR illustrate how transmission planning processes are resistant to changes when the

[1522] Southeast PIOs Initial Comments at 50.

[1523] Southeast PIOs Reply Comments at 23, 27.

[1524] SREA Reply Comments at 26 (citing Louisiana Commission Initial Comments at 17; Mississippi Commission Initial Comments at 11; Southern Initial Comments at 12).

[1525] R Street Initial Comments at 9.

Commission provides latitude for discretion.[1526] Concerned Scientists further contend that the discretion provided in the NOPR will allow a pattern of undue discrimination and unjust and unreasonable rates to persist that initially motivated the Commission to act.[1527]

687. Some commenters assert that requiring the same benefits in different transmission planning regions will help increase interregional transmission coordination.[1528] Clean Energy Associations argue that it is important for transmission planning regions to have a common starting point in terms of which benefits they evaluate to facilitate greater interregional transmission coordination.[1529] Breakthrough Energy notes that load diversity—and its effect on reducing very expensive generation capacity costs—is a major and under-appreciated benefit of large-scale interregional transmission facilities.[1530] Grid United states that, without a minimum set of benefits criteria, disparate benefits in neighboring transmission planning regions could balkanize the grid and disrupt effective interregional transmission planning, emphasizing the need for a set of principles that outline benefits that are universal and necessary for effective long-term

[1526] Concerned Scientists Reply Comments at 7.

[1527] *Id.* at 8-9.

[1528] Breakthrough Energy Initial Comments at 22-23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27-28; US DOE Initial Comments at 31-32.

[1529] Clean Energy Associations Initial Comments at 19.

[1530] Breakthrough Energy Initial Comments at 22.

transmission planning.[1531] Policy Integrity asserts that defining a uniform set of minimum benefits would facilitate better identification and selection of efficient and cost-effective transmission solutions and would ensure comparability of transmission expansion projects across different RTOs/ISOs, which will be particularly useful given the need to improve Interregional Transfer Capability.[1532]

688. Relatedly, PJM states that, while it agrees that transmission providers should have flexibility to propose which benefits make sense to consider for their own transmission planning regions, the Commission should adopt a core set of benefits to be considered nationwide to ensure consistency.[1533] SREA notes that, in RTOs/ISOs, seams are perpetually a problem due to a lack of common national standards on benefits metrics and data inputs and asserts that the Commission should set minimum standards.[1534]

689. Some commenters assert that a failure to consider sufficient benefits could result in higher costs and/or unjust and unreasonable rates.[1535] According to Enel, without

[1531] Grid United Initial Comments at 3.

[1532] Policy Integrity Initial Comments at 3, 27-28.

[1533] PJM Initial Comments at 93 (citing NOPR, 179 FERC ¶ 61,028 at P 186).

[1534] SREA Reply Comments at 26-27.

[1535] Enel Initial Comments at 3; Clean Energy Association Initial Comments at 20; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy – Florida Supplemental Comments at 1; Conservatives for Clean Energy – South Carolina Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum Supplemental Comments at 1; Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy

considering a larger number of benefits, transmission projects that would have large net benefits will not be selected if no benefits or even only a small number of potential benefits were compared against the upfront costs.[1536]

690. Some commenters assert that a failure to require consideration of specific benefits will undermine other aspects of the NOPR's proposed reforms.[1537] Anbaric, for instance, argues that the NOPR falls far short of requiring comprehensive transmission planning, because it does not propose to mandate the use of any specific set of benefits.[1538] RMI contends that there is overwhelming evidence that transmission infrastructure provides multiple, diverse benefits, as well as established precedent that transmission costs should be allocated roughly commensurate with benefits. Therefore, RMI states, it would be illogical to allow transmission providers to ignore any benefits that transmission infrastructure offers, as it would lead to flawed investment decisions and defective cost allocation. RMI asserts that transmission providers should be required to quantify the full suite of known benefits of transmission infrastructure in Long-Term Regional Transmission Planning and that the list of 12 benefits in the NOPR is conservative and does not double-count benefits.[1539]

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Forum Supplemental Comments at 1.

[1536] Enel Initial Comments at 3.

[1537] Anbaric Initial Comments at 6-7; RMI Initial Comments at 2.

[1538] Anbaric Initial Comments at 6-7.

[1539] RMI Initial Comments at 2.

691. AEE argues that several of the listed benefits are indisputably relevant to all transmission planners and that these benefits should form a core group of minimum considerations.[1540] AEE states that the Commission may wish to conduct additional fact-finding in this docket to consider whether additional benefits cut across all markets and transmission planning regions or whether it is necessary to require each region to identify region-specific benefits for inclusion.[1541] Hannon Armstrong states that the Commission indicated that each of the 12 benefits listed in the NOPR has the potential to provide a meaningful contribution to offset the cost of transmission and recommends that, absent any double-counting in this list, the Commission should require each of these benefits to be evaluated.[1542] ITC argues that the Commission should adopt as minimum benefit criteria for project evaluation those used in the recently approved MISO Long-Range Transmission Plan process.[1543]

692. Southeast PIOs claim that the Commission must establish a set of minimum benefits for transmission providers to incorporate in their assessment of regional transmission facilities to ensure that regional transmission facilities are accurately represented in the transmission planning process.[1544] Southeast PIOs contend that a

[1540] AEE Initial Comments at 26.

[1541] *Id.*

[1542] Hannon Armstrong Initial Comments at 2-3.

[1543] ITC Initial Comments at 5, 18-22.

[1544] Southeast PIOs Initial Comments at 50.

regional transmission planning process that quantifies and fully accounts for benefits of regional transmission alternatives would provide a measure of assurance to regulators and stakeholders that such alternatives were evaluated appropriately.[1545] In response to Southern and SERTP, Southeast PIOs argue that quantifying the listed benefits does not itself make resource decisions; the benefits are meant to determine the value proposition of alternative regional transmission facilities.[1546]

693. GridLab states that the Commission should require transmission providers to justify why their transmission solution evaluation frameworks omit any categories of benefits in relation to a standard list of benefits like those proposed in the NOPR.[1547] Pattern Energy agrees and notes that a "common starting point" would lower barriers to entry for market participants that do business in multiple transmission planning regions. Moreover, Pattern Energy argues that a required set of standardized benefits would facilitate a more transparent transmission planning process, as developers would have a baseline knowledge of any single transmission provider's transmission planning process regardless of where they are located.[1548]

[1545] *Id.* at 53.

[1546] Southeast PIOs Reply Comments at 28 (citing Southern Initial Comments at 25-26; SERTP Sponsors Initial Comments at 30).

[1547] GridLab Initial Comments at 25.

[1548] Pattern Energy Reply Comments at 6-8 (citing ACEG Initial Comments at 32; Clean Energy Associations Initial Comments at 21).

694. Tabors Caramanis Rudkevich states that when transmission planning analyses account for the benefits of capital cost savings, resource adequacy, and resilience, the total benefits of transmission infrastructure well exceed the cost.[1549] Tabors Caramanis Rudkevich provides an example of multi-value benefit stacking for the transmission line connecting ERCOT and Southern Company and states that the results show total benefits of $390 million, compared to $33 million when considering production cost savings alone.[1550]

695. Certain TDUs and NESCOE support or are amenable to a requirement for minimum benefits that also allows for flexibility in determination of additional benefits.[1551] Specifically, NESCOE recommends that the Commission establish a list of benefits that must be considered for a regional discussion on transmission cost allocation and that the benefits list in the NOPR is an appropriate starting point. However, NESCOE contends, after consulting with the states, transmission providers should have the flexibility to include additional benefits or remove benefits from the list, asserting that such an approach would help facilitate collaboration in determining the appropriate set of benefits for a transmission planning region.[1552] NESCOE also argues that, because

[1549] Tabors Caramanis Rudkevich Initial Comments at 6.

[1550] *Id.*

[1551] Certain TDUs Initial Comments at 2-3, 9-12; NESCOE Initial Comments at 43-44.

[1552] NESCOE Initial Comments at 44.

benefits and the methods of measuring them may change over time, the Commission should clarify in any final rule that transmission providers may modify or add benefits in future FPA section 205 filings.[1553]

696. Certain TDUs also urge the Commission to allow for regional flexibility and state involvement in determining other measurable and quantifiable benefits to use in evaluating Long-Term Regional Transmission Facilities.[1554] While arguing for requiring certain benefits, Cypress Creek states that it agrees with Brattle Group that requiring evaluation of all 12 benefits in every scenario would detract from necessary regional flexibility.[1555] Cypress Creek asserts that the Commission should require two additional project/region-specific benefits in evaluating multi-value projects but does not explain what they should be.[1556]

697. Exelon supports the Commission's proposal to provide flexibility to each transmission planning region to identify which benefits they will use in Long-Term Regional Transmission Planning. For instance, Exelon suggests that congestion reduction is more applicable to regions with Locational Marginal Price pricing, while it may be impossible to calculate the benefits of deferred generation capacity investments in

[1553] *Id.* at 43-44.

[1554] Certain TDUs Initial Comments at 9.

[1555] Cypress Creek Reply Comments at 7-8 (citing PIOs Initial Comments Ex. A, ¶¶ 8-9).

[1556] *Id.* at 8.

a region like PJM where generation capacity is largely market-driven.[1557] Similarly, the New Jersey Commission recommends providing regional flexibility to include additional benefits that may be harder to quantify and/or do not reduce customers' bills (e.g., resilience benefits and the value of meeting state public policies).[1558]

698. Clean Energy Buyers state that the proposed set of benefits is generally appropriate and that a common set of benefits would allow for the proper identification of benefits in Long-Term Regional Transmission Planning, accounting for changes in the resource mix and demand, and facilitating stakeholder participation. Therefore, Clean Energy Buyers argue, the Commission should require transmission providers to adopt a set of Commission-identified benefits that are consistent with the just and reasonable standard or demonstrate on compliance why they should not have to do so. That said, Clean Energy Buyers state that the Commission should permit transmission providers to propose processes for weighing benefits in accordance with their relative importance in each specific transmission planning region.[1559]

699. Several commenters recognize that benefits analysis can be resource intensive and therefore recommend that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before

[1557] Exelon Initial Comments at 15.

[1558] New Jersey Commission Initial Comments at 14.

[1559] Clean Energy Buyers Initial Comments at 19-21.

investing staff resources and modeling work to provide a detailed quantification.[1560] Clean Energy Buyers argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits listed in the NOPR and quantify them accordingly.[1561] Hannon Armstrong states that while certain benefits may have a zero or *de minimis* contribution for certain candidate transmission projects, the Commission should require transmission providers to document each potential benefit by using a high-level screening analysis or detailed modeling as applicable.[1562] PIOs assert that screening tools can be used to reduce analytical burdens, allowing transmission providers to self-certify compliance and/or provide justifications for when benefits do not apply.[1563]

### i. List of Benefits Proposed in the NOPR

700. Some commenters support requiring transmission providers to consider all 12 illustrative benefits enumerated in the NOPR.[1564] ACORE contends that these categories

[1560] ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9; Interwest Initial Comments at 12-13; WATT Coalition Initial Comments at 7.

[1561] Clean Energy Buyers Initial Comments at 20-21.

[1562] Hannon Armstrong Initial Comments at 2-3

[1563] PIOs Initial Comments at 41.

[1564] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial

represent a best practice and track closely with recommended multi-benefit planning approaches.[1565] Breakthrough Energy notes that some of the Commission-listed benefits can be very significant but are typically ignored in today's transmission planning processes.[1566] SEIA and Fervo assert that the final rule should account for the full range of transmission benefits and use multi-value planning to comprehensively identify investments that address all categories of needs and benefits.[1567]

701. PIOs state that there is strong evidence in the record to support the proposed list of benefits, including extensive testimony provided by the Brattle Group and others. PIOs state that these benefits all correlate with needs and goals associated with Long-Term Regional Transmission Planning and, as such, the Commission should require transmission providers to consider them for most, if not all, regional transmission projects. Finally, PIOs encourage the Commission to make clear that these benefits should be assessed as part of any transmission planning process—even those conducted for economic purposes.[1568]

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Comments at 50.

[1565] ACORE Initial Comments at 12 (citing Rob Gramlich, Grid Strategies LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis*, at 9 (Aug. 9, 2022)).

[1566] Breakthrough Energy Initial Comments at 22.

[1567] Fervo Reply Comments at 2; SEIA Initial Comments at 16.

[1568] PIOs Initial Comments at 37-38, 41.

702. Amazon supports the list of benefits set forth in the NOPR and urges the Commission to make consideration of those benefits mandatory except insofar as a transmission provider files for waiver and overcomes a strong presumption of their relevance to transmission planning and cost allocation.[1569] To facilitate the responsible construction of transmission facilities, ENGIE recommends that the Commission incorporate the 12 listed benefits as a minimum set of benefits for analysis but permit flexibility in how transmission providers conduct their analysis.[1570]

### ii. Application of the Benefits of Long-Term Regional Transmission Facilities in Non-RTO/ISO Regions

703. Certain commenters state that all or most of the Commission's proposed benefits are applicable and appropriate in non-RTO/ISO transmission planning regions.[1571] For example, ACEG states the minimum set of benefits should be implemented as universally as possible across RTOs/ISOs and non-RTO/ISO regions.[1572] PIOs state that the Brattle-Grid Strategies Oct. 2021 Report shows the numerous benefits not currently quantified in RTO/ISO regions to consumers' detriment and that the problem is more dire in non-RTO/ISO regions.[1573] Relatedly, MISO states that benefits could be applied in non-

[1569] Amazon Initial Comments at 5.

[1570] ENGIE Reply Comments at 3.

[1571] ACEG Initial Comments at 32, 48, 61; PIOs Initial Comments at 42; SEIA Initial Comments at 17.

[1572] ACEG Initial Comments at 32.

[1573] PIOs Initial Comments at 42.

RTO/ISO regions but may be limited or not fully realized due to less coordinated congestion management and transmission planning.[1574]

704. SEIA comments that the Commission should mandate the consideration of benefits of Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions. Otherwise, SEIA states, transmission providers could rely on state integrated resource planning processes, which do not incorporate lower cost transmission alternatives to generation procurement, potentially leading to transmission expansion to accommodate higher-cost generation than is needed. According to SEIA, there is no basis to apply different benefits in non-RTO/ISO transmission planning regions, because many of the proposed benefits of Long-Term Regional Transmission Facilities have already been calculated in non-RTO/ISO regions.[1575]

705. Southeast PIOs claim that Southeastern transmission providers should not be exempt from quantifying benefits, even if some benefits do not apply in the same manner to non-RTO/ISO transmission planning regions as they do to RTO/ISO regions.[1576] Southeast PIOs advocate for the Commission to establish standardized metrics for both RTO/ISO regions and non-RTO/ISO regions to capture similar benefits.[1577] Otherwise, Southeast PIOs argue, transmission providers will continue to focus only on costs,

[1574] MISO Initial Comments at 51.

[1575] SEIA Initial Comments at 17-18.

[1576] Southeast PIOs Initial Comments at 51.

[1577] *Id.* at 52.

thereby depriving states and stakeholders of a fuller picture of transmission planning options.[1578] TAPS contends that no transmission facilities have been selected in a regional transmission plan for purposes of cost allocation since the implementation of Order No. 1000 in non-RTO/ISO transmission planning regions partly because of the narrow factors that most non-RTO/ISO regions consider in evaluating the benefits of potential transmission projects.[1579]

706. Other commenters express concern that certain NOPR benefits would be inapplicable or problematic to apply to non-RTO/ISO transmission planning regions or argue that the same types of benefits should not be applied to both sets of regions.[1580] California Municipal Utilities oppose applying the list of benefits to non-RTO/ISO transmission planning regions, stating that doing so would misapprehend the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and to provide consumer protection measures to guard against speculative transmission projects.[1581] Dominion states that a one-size-fits-all approach to

[1578] *Id.* at 52-53.

[1579] TAPS Initial Comments at 15.

[1580] California Municipal Utilities Reply Comments at 5-6; Dominion Reply Comments at 2; Duke Initial Comments at 23; EEI Initial Comments at 19; Idaho Power Initial Comments at 8; North Carolina Commission and Staff Initial Comments at 7; Southern Initial Comments at 25-27.

[1581] California Municipal Utilities Reply Comments at 5-6.

benefits may be inappropriate, for instance, in locations where some transmission providers operate outside of an RTO/ISO while others function within an RTO/ISO.[1582]

707. EEI and Idaho Power state that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion or increased market liquidity.[1583] Likewise, North Carolina Commission and Staff state that some of the benefits proposed for consideration are only applicable in RTOs/ISOs (e.g., increased market liquidity) and argue that some benefits could conflict with state-jurisdictional resource decisions (e.g., production cost savings, access to lower-cost generation).[1584]

708. Southern states that, while certain benefits identified in the NOPR could work for Southern's non-RTO/ISO footprint, others could harm underlying state integrated resource planning/request for proposal processes or are suited only for RTO/ISO markets, such as increased market liquidity.[1585] For example, Southern states that considering production cost savings effectively would make generation resource-related decisions that would intrude into integrated resource plan/request for proposal planning, which considers the total costs (including both generation and transmission costs) of available alternatives to customers.[1586] Similarly, SERTP Sponsors state that, because SERTP

[1582] Dominion Reply Comments at 2.

[1583] EEI Initial Comments at 19; Idaho Power Initial Comments at 8.

[1584] North Carolina Commission and Staff Initial Comments at 7.

[1585] Southern Initial Comments at 25-27.

[1586] *Id.* at 26.

Sponsors continue to use integrated resource plan/request for proposal planning to make their resource and load determinations, some of the benefits that are appropriate for consideration in RTOs/ISOs are inapplicable for transmission planning or cost allocation purposes in the Southeast.[1587] SERTP Sponsors further state that, as the states have exclusive jurisdiction over such integrated resource plan/generation matters, requiring consideration of "[integrated resource plan/request for proposal]-related benefits," including production cost savings, capacity costs benefits, reduced planning reserve margins, and reduced peak energy losses, could exceed the Commission's jurisdiction by infringing on such state processes.[1588]

709. Kentucky Commission Chair Chandler argues against SERTP Sponsors' comments that suggest that integrated resource plan/request for proposal processes already consider four of the proposed categories of benefits included in the NOPR. Kentucky Commission Chair Chandler contends that the integrated resource planning/request for proposal process can only address these four categories on a utility-by-utility basis and, thus, is unable to plan for transmission facilities across utilities or transmission planning regions by nature.[1589]

710. Some commenters advocate for or against requiring transmission providers to consider other specific lists, categories, or combinations of benefits, arguing that such

[1587] SERTP Sponsors Initial Comments at 30.

[1588] SERTP Sponsors Initial Comments at 30.

[1589] Kentucky Commission Chair Chandler Reply Comments at 7.

approaches reduce possible duplication of benefits, increase flexibility, and/or focus on benefits they believe are most important.[1590] PIOs, for example, assert that some commenters who are opposed to the list of benefits in the NOPR nonetheless agree that transmission planners should quantify broad categories of benefits to plan effectively.[1591] AEP states that some benefits are more difficult to calculate than others and argues that the minimum set of benefits it recommends appropriately balances the significance of each type of benefit with the difficulty of quantifying that benefit.[1592]

711. AEP and GridLab argue that many of the benefits listed in the NOPR measure or identify the same type of benefit and therefore argue that the Commission should group similar benefits together into categories to avoid double-counting.[1593] Specifically, AEP and GridLab propose that the production cost savings and access to lower-cost generation benefits be grouped into a required category.[1594] In addition, AEP states that the reduced loss of load probability, reduced planning reserve margin, capacity cost benefits from

[1590] ACEG Reply Comments at 6-7; AEE Reply Comments at 25-26; AEP Initial Comments at 6, 23-25; California Commission Initial Comments at 31-34; Certain TDUs Reply Comments at 1-2; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PIOs Reply Comments at 7-9; PJM Initial Comments at 94-96; PPL Initial Comments at 14.

[1591] PIOs Reply Comments at 7-8 (citing Entergy Initial Comments at 21; Exelon Initial Comments at 15).

[1592] AEP Initial Comments at 23.

[1593] AEP Initial Comments at 23-24; GridLab Initial Comments at 27.

[1594] AEP Initial Comments at 25; GridLab Initial Comments at 27.

reduced peak energy losses, and deferred capacity investments benefits should be combined into one required category.[1595]

712. GridLab and PJM contend that the Commission should combine the benefits of reduced loss of load probability and deferred generation capacity investment into a single category of benefits.[1596] PJM further argues that the Commission should combine the benefits of mitigation of extreme events and mitigation of weather and load uncertainty.[1597]

713. California Commission recommends that to capture the benefits of transmission infrastructure, the Commission should require transmission providers to assess benefits within the following six benefit categories: (1) production cost benefits; (2) emissions reductions benefits; (3) generation capital cost benefits; (4) risk mitigation benefits; (5) resource adequacy benefits; and (6) resilience benefits. California Commission states that such a requirement would promote greater uniformity in how the benefits of regional (and interregional) transmission projects are evaluated, reducing potential disputes over cost allocation.[1598] However, California Commission argues, the Commission should allow transmission providers, in consultation with Relevant State Entities, to define each

[1595] AEP Initial Comments at 25.

[1596] GridLab Initial Comments at 27; PJM Initial Comments at 95.

[1597] PJM Initial Comments at 94.

[1598] California Commission Initial Comments at 33.

identified benefit and determine how to quantify it.[1599] To ensure that customers are protected from speculative transmission development and unreasonably high costs, California Commission concludes that the Commission should require transmission providers to demonstrate on compliance that they identified and defined benefits within each of the required benefit categories and determined appropriate quantification methods through a transparent public process.[1600]

714. Joint Consumer Advocates state that the following categories of benefits should be included in Long-Term Regional Transmission Planning: (1) production cost savings; (2) avoided or deferred reliability transmission facilities; and (3) aging transmission infrastructure replacement.[1601]

715. AEE notes that some commenters propose that the Commission adopt a smaller set of benefit categories.[1602] AEE states that while there may be value in considering these proposals, they miss important benefits such as increased competition, market liquidity, and increased resilience from mitigation of extreme weather events effects and system contingencies.[1603] Thus, AEE recommends that the Commission adopt as mandatory the

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[1599] *Id.* at 28-29.

[1600] *Id.* at 34-35.

[1601] Joint Consumer Advocates Initial Comments at 11.

[1602] AEE Reply Comments at 25-26 (citing PJM Initial Comments at 93-96; California Commission Initial Comments at 32; New Jersey Commission Initial Comments at 13-14).

[1603] *Id.*

full set of 12 benefits listed in the NOPR but allow a transmission provider to demonstrate that an alternative set of benefits captures all the benefits of transmission in its transmission planning region.

716. A few commenters offer categories of benefits while noting the importance of regional flexibility.[1604] ACEG notes widespread support for the Commission to require certain categories of minimum benefits and requests flexibility for transmission providers to address these categories in accordance with regional needs. ACEG states that considering categories of benefits will reduce the risk of double-counting or miscalculating benefits and allow flexibility to apply specific benefits best suited to each transmission planning region.[1605]

717. In addition to concerns expressed by commenters in the context of the combinations of benefits proposed above, other commenters express concern regarding the potential for double-counting of benefits if transmission providers are required to consider certain benefits.[1606] For example, NRECA asserts that accounting for increased competition and increased market liquidity would risk double-counting benefits,[1607] and

[1604] ACEG Reply Comments at 6-7; Entergy Initial Comments at 21.

[1605] ACEG Reply Comments at 6-7 (citing Entergy Initial Comments at 21; AEP Initial Comments at 23-27; Exelon Initial Comments at 15-16).

[1606] *See, e.g.*, APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 10-11; Louisiana Commission Reply Comments at 10; Michigan Commission Initial Comments at 6; Nevada Commission Initial Comments at 10-11; Utah Division of Public Utilities Initial Comments at 8; Vistra Initial Comments at 16-17.

[1607] NRECA Initial Comments at 45 (citing NRECA Initial Comments, attach. at

Utah Division of Public Utilities argues that accounting for both reduction in loss of load probability and mitigation of extreme events and system contingencies would result in double-counting.[1608] Clean Energy Buyers ask that the Commission require transmission providers to explain how they will avoid double-counting issues,[1609] while ISO-NE seeks more information from the Commission regarding which benefits the Commission believes are redundant.[1610]

718. A few commenters state that the list of 12 benefits in the NOPR does not risk double-counting.[1611] DC and MD Offices of People's Counsel concludes that each benefit in this list is mutually exclusive, noting that some transmission providers may wish to mix and match these benefits because their modeling tools may not disaggregate them in exactly the way described in the NOPR.[1612] MISO notes that there are instances where one benefit can enable other benefits and that adopting a calculation method that recognizes that complementary behavior can yield incremental value.[1613] For example, MISO states, a calculation approach that distinguishes between the benefit of enabling

16-17).

[1608] Utah Division of Public Utilities Initial Comments at 8.

[1609] Clean Energy Buyers Initial Comments at 20-21.

[1610] ISO-NE Initial Comments at 34.

[1611] DC and MD Offices of People's Counsel Initial Comments at 20; MISO Initial Comments at 50.

[1612] DC and MD Offices of People's Counsel Initial Comments at 20.

[1613] MISO Initial Comments at 50.

resource expansion and the benefit of increased transmission capability provided by regional transmission projects would produce unique benefits.[1614]

### c. Commission Determination

719. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure a set of seven required benefits (required benefits) for Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of Long-Term Regional Transmission Planning. Furthermore, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use these measured benefits to evaluate Long-Term Regional Transmission Facilities, as discussed below in the Evaluation and Selection of Regional Transmission Facilities section. This Evaluation of the Benefits of Regional Transmission Facilities section discusses this final rule's requirements with regard to transmission providers' measurement and use of benefits in evaluating Long-Term Regional Transmission Facilities; however, as discussed in the Development of Long-Term Scenarios section, these same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.[1615]

720. The seven required benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, which we describe in greater detail

[1614] *Id.*

[1615] *See supra* Long-Term Regional Transmission Planning, Development of Long-Term Scenarios section.

in the discussion of the individual benefits below, are: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.[1616]

721. We find that these requirements are necessary to ensure that transmission providers can evaluate Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs. Specifically, we find that transmission providers must measure these seven required benefits in each Long-Term Scenario because, as discussed further in the Evaluation and Selection of Regional Transmission Facilities section, evaluating Long-Term Regional Transmission Facilities for potential selection necessarily involves the consideration of the benefits measured in each Long-Term Scenario and sensitivity to help address uncertainty over the 20-year transmission planning horizon and to maximize benefits accounting for costs over time. As such, we find that, to ensure just and reasonable Commission-jurisdictional rates, transmission providers must measure, at minimum, the set of seven required benefits in Long-Term Regional Transmission

[1616] We discuss modifications to Benefit 6 from its description in the NOPR in the Benefit 6 determination section.

Planning and then use them to evaluate Long-Term Regional Transmission Facilities for selection.

722. Although the Commission did not propose to require the use of any specific benefits in the NOPR, the Commission sought comment on whether it should require transmission providers to use some or all of the potential benefits described in the NOPR as a minimum set of benefits in Long-Term Regional Transmission Planning. The record in this proceeding shows that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it is necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. We find that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

723. By requiring the measurement and use of the seven enumerated benefits in Long-Term Regional Transmission Planning, we ensure that transmission providers will consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. In contrast, adopting the more

flexible approach proposed in the NOPR would not address the identified deficiencies in existing regional transmission planning and cost allocation processes because such an approach would fail to ensure that transmission providers consider the broader set of benefits provided by, and the beneficiaries receiving the benefits of, Long-Term Regional Transmission Facilities, and thus, may fail to identify the potentially more efficient or cost-effective regional transmission solution. We find that failing to use the set of benefits that we require in this final rule to evaluate Long-Term Regional Transmission Facilities for potential selection could render resulting Commission-jurisdictional rates unjust and unreasonable. We find that not requiring transmission providers to use certain benefits to evaluate Long-Term Regional Transmission Facilities would be expected to lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected.[1617] In addition, we find that the transparency provided by requiring consideration of a sufficiently broad and common set of benefits will help to ensure the costs of Long-Term Regional Transmission Facilities are allocated to beneficiaries in a manner that is at least roughly commensurate with the benefits they derive from them.[1618]

[1617] *See* Clean Energy Associations Initial Comments at 20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses*, at 26 (Apr. 2021)).

[1618] *ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

724. We appreciate arguments made by certain commenters that failure to incorporate identifiable benefits risks skewing the evaluation process against developing needed and beneficial Long-Term Regional Transmission Facilities because transmission providers would consider all of the costs of such transmission facilities without similarly considering many important benefits that they may provide.[1619] However, we are also cognizant of concerns about duplication of benefits and difficulty of measuring certain benefits. In this final rule, rather than requiring transmission providers to measure and use all 12 benefits enumerated in the NOPR, we only require transmission providers to measure and use seven specific benefits that have a proven track record, can be discretely measured, and are unlikely to cause duplication. We find that the modification to the NOPR proposal to require the measurement and use of these seven benefits to evaluate Long-Term Regional Transmission Facilities, as discussed above, resolves concerns about important benefits being omitted from Long-Term Regional Transmission Planning, as well as challenges raised concerning duplication and measurement of certain benefits.

725. We acknowledge that many commenters do not favor requiring the use of particular benefits. In response, we emphasize that a set of common benefits and a requirement to measure and use those benefits in Long-Term Regional Transmission Planning will ensure just and reasonable rates, as discussed above.[1620] Specifically,

[1619] *See* Enel Initial Comments at 3.

[1620] *See* ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at

unless transmission providers consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs, they may fail to identify the more efficient or cost-effective regional transmission solution, resulting in relatively inefficient or less cost-effective transmission development.

726. We note that some commenters request flexibility to use different benefits, such as SPP, which states that the effort required to incorporate additional benefit metrics into its current regional transmission planning process cannot be accommodated within its

6, 23-25; Breakthrough Energy Initial Comments at 4, 21-22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11-12; Clean Energy Buyers Reply Comments at 8-9; Concerned Scientists Reply Comments at 7-10; Cypress Creek Reply Comments at 7-8; DC and MD Offices of People's Counsels Reply Comments at 3, 7-8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16: Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18-22; Interwest Initial Comments at 12; Interwest Reply Comments at 6-7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11-14; Pacific Northwest State Agencies Initial Comments at 16-17; PIOs Initial Comments at 27-28; PIOs Reply Comments at 7-8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16-17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27-28; ; US DOE Initial Comments at 30-33; US Senator Schumer Supplemental Comments at 1-2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

current process timeline.[1621] As discussed in the Implementation and Compliance sections of this final rule, we require transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles), and thus transmission providers will not be required to immediately implement this reform.

727. Some commenters argue that the requirement to measure and use these benefits will increase costs and require additional effort, and that the Commission has presented insufficient evidence that this requirement will produce the desired benefits.[1622] Commenters who express such concerns did not provide persuasive evidence to suggest that requiring the measurement and use of a required set of benefits would be unduly burdensome. While measuring these benefits may impose a degree of burden on some transmission providers, the requirement for transmission providers to measure and use the seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that rates are just and reasonable. Specifically, absent a requirement that transmission providers measure and use a sufficiently broad range of benefits of Long-Term Regional Transmission Facilities when evaluating them for potential selection, transmission providers may not identify, evaluate, and select more efficient or cost-

[1621] SPP Initial Comments at 18.

[1622] *E.g.*, Dominion Initial Comments at 34-35.

effective regional transmission solutions to Long-Term Transmission Needs, which may lead to relatively inefficient or less cost-effective transmission development. Further, we believe that experience gained by transmission providers will over time allow them to perform the necessary measurements more efficiently. Moreover, in our discussion of each required benefit below, we provide a description, for several of the required benefits, of at least one manner in which transmission providers could measure each required benefit. Finally, commenters also did not provide persuasive evidence that the burdens of measuring and using a required set of benefits outweigh the benefits of using these benefits in Long-Term Regional Transmission Planning. We therefore find that any burdens of measuring and using the seven required benefits in Long-Term Regional Transmission Planning are outweighed by the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs.[1623]

728. Another common concern expressed by some commenters is that requiring a minimum set of benefits would undermine regional flexibility.[1624] We conclude that it would be inappropriate to provide flexibility not to consider this required set of benefits in Long-Term Regional Transmission Planning because, as described above, requiring the measurement and use of these benefits ensures that transmission providers are able to

[1623] *See* Clean Energy Associations Initial Comments at 20 ("Not requiring benefits to be evaluated could lead to higher costs in the long-term, and, thus, unjust and unreasonable rates.").

[1624] *E.g.*, Entergy Initial Comments at 21.

identify, evaluate, and select regional transmission solutions to more efficiently or cost-effectively address Long-Term Transmission Needs, and thereby ensures just and reasonable rates. We therefore disagree with Dominion that transmission providers should be permitted to identify initial benefits that they will consider in conducting Long-Term Regional Transmission Planning but retain flexibility in applying such benefits to each transmission provider's individual circumstances.[1625] However, as we discuss further below, we are providing flexibility to transmission providers regarding how they will measure each of the required benefits.

729. Transmission providers may also propose to measure and use additional benefits in Long-Term Regional Transmission Planning, as discussed below in the Other Benefits section. This approach provides flexibility to transmission providers in how they implement the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning, while maintaining the baseline requirement that they measure and use all seven benefits included in that required set of benefits, in order to ensure that rates remain just and reasonable. Requiring all transmission providers to measure and use a required set of benefits will help to improve interregional transmission coordination among different transmission planning regions, as noted by commenters.[1626]

[1625] Dominion Initial Comments at 34.

[1626] Breakthrough Energy Initial Comments at 22-23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27-28; US DOE Initial Comments at 31-32.

730. In addition, as more fully described below, we also find that the seven benefits we require are not overly burdensome to calculate. We address such concerns for individual benefits in more detail within the determination section on each benefit below.

731. Some commenters assert that some benefits are only appropriate for use in RTO/ISO transmission planning regions.[1627] We believe that all seven required benefits can be calculated in both RTO/ISO and non-RTO/ISO transmission planning regions, as noted by ACEG.[1628] In particular, we note that all seven required benefits have either been approved for use in regional transmission planning in at least one non-RTO/ISO transmission planning region or may be implemented by building upon the modeling or techniques used to measure benefits in RTO/ISO or non-RTO/ISO regions, or both.

732. As described below, in the NOPR, the Commission noted that it approved the use of production cost savings (i.e., Benefit 3) to evaluate Order No. 1000 economic transmission projects in a non-RTO/ISO transmission planning region.[1629] We note that, as measurements of reduced production costs outside of normal conditions, the measurement methods for Benefit 5, Reduced Congestion Due to Transmission Outages, and Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, may be built upon the modeling used to measure Benefit 3. Separately, the

[1627] Pacific Northwest Utilities Initial Comments at 8-10; SERTP Sponsors Initial Comments 29-30; Southern Initial Comments at 25-27.

[1628] ACEG Initial Comments at 48.

[1629] NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, at P 314 (2013)).

Commission has accepted use of benefits in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,[1630] and Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.[1631] In the NOPR, the Commission likewise noted that it has accepted accounting for the avoided costs (i.e., Benefit 1) as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO transmission planning regions.[1632] With respect to Final Rule Benefit 7 (i.e., capacity cost benefits from reduced peak energy losses), the avoided costs associated with this benefit are comparable across RTO/ISO and non-RTO/ISO transmission planning regions. Transmission providers in all transmission planning regions incur capital costs to meet installed generation requirements and to maintain reliable operations. Transmission expansions may help reduce peak energy losses, and under this benefit, result in capital cost savings associated with the reduction in installed generation requirements.

733. We disagree with commenters that express concerns that required benefits would conflict with state-regulated integrated resource planning processes.[1633] As discussed in

[1630] *PacifiCorp*, 147 FERC ¶ 61,057, at PP 133-134, 141-143 (2014); *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314.

[1631] *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141-143.

[1632] NOPR, 179 FERC ¶ 61,028 at PP 189-190 & n.326 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

[1633] SERTP Sponsors Initial Comments at 30; Southern Initial Comments at 24-26.

the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, nothing in this final rule infringes on the states' reserved authority under FPA section 201.

734. Entergy argues that the Commission should recognize that not all benefits are created equal for all jurisdictions and that some states will want transmission projects that actually reduce customer bills to have clear priority.[1634] We believe that the required measurement and use of the required set of benefits can accommodate such preferences. Our requirements ensure that all benefits are measured transparently and considered in selection decisions. In addition, our required set of benefits captures considerations such as production cost savings that can flow through to customer bills. PJM, for example, notes that lower production costs will generally also reduce market prices for electricity as lower-cost suppliers will set market clearing prices more frequently than without the transmission project.[1635] We note that while this final rule requires the measurement and use of the required set of benefits, it is the evaluation process, including selection criteria, that transmission providers propose on compliance that will inform which Long-Term Regional Transmission Facilities are selected. Transmission providers may propose an evaluation process, including selection criteria, that reflect regional preferences as long as those criteria meet the requirements set forth below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[1634] Entergy Initial Comments at 21.

[1635] PJM Initial Comments at 95.

735. ISO-NE notes that the Commission sought information on potential double-counting of benefits and requests that the Commission clarify which benefits the Commission believes are redundant.[1636] We believe that the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting. Nonetheless, to the extent that transmission providers are concerned that any possibility of double-counting remains, we provide transmission providers with flexibility on the measurement of such benefits and expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address those concerns.

736. Some commenters urge the Commission to adopt a combination or categorical approach toward benefits, under which required benefits would be grouped under certain categories or combinations.[1637] We decline to adopt this approach, largely because our analysis and review of the record suggests that such an approach could reduce transparency regarding the benefits that we are requiring. For example, in some cases adopting a combination or categories approach could obfuscate individual benefit calculations within a category, making it less clear to interested parties what specific

[1636] ISO-NE Initial Comments at 34.

[1637] ACEG Reply Comments at 6-7; AEP Initial Comments at 23-25; California Commission Initial Comments at 33; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PJM Initial Comments at 94-96.

benefits a Long-Term Regional Transmission Facility may provide. Additionally, we find that these seven benefits merit individual measurement and evaluation.

737. Northwest and Intermountain and NYISO ask that the final rule confirm that the 12 illustrative benefits described in the NOPR are not exhaustive.[1638] First, we confirm that the list of 12 illustrative benefits described in the NOPR is not an exhaustive list of the potential benefits of Long-Term Regional Transmission Facilities. Second, we reiterate that the required set of benefits adopted in this final rule is a subset of the benefits listed in the NOPR, as modified in the discussions below. Transmission providers may be aware of additional benefits beyond those included in the required set of benefits, or the 12 illustrative benefits described in the NOPR, and we provide them with the flexibility to propose to measure and use additional benefits in Long-Term Regional Transmission Planning so long as they do so in a manner that is consistent with transmission providers' obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes. In particular, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected to address Long-Term Transmission Needs.[1639] This necessarily means that

[1638] Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

[1639] *See infra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits that we require transmission providers to include in their OATTs. We find that this transparency strikes an appropriate balance between ensuring that transmission providers measure and use the seven required benefits in Long-Term Regional Transmission Planning and allowing flexibility for transmission providers to use additional benefits that they believe will reasonably reflect the benefits of a Long-Term Regional Transmission Facility or Facilities in their transmission planning regions.

738. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.[1640] We clarify that transmission providers must use the required set of benefits to evaluate Long-Term Regional Transmission Facilities in every Long-Term Regional Transmission Planning cycle, and we discuss the use of other benefits to evaluate Long-Term Regional Transmission Facilities in the Other Benefits section of this final rule.

739. Some commenters suggest that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before investing staff resources and modeling work to provide a detailed quantification.[1641]

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[1640] OMS Initial Comments at 8.

[1641] ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9;

Clean Energy Buyers similarly argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits described in the NOPR and quantify them accordingly.[1642] We find such screening approaches, as advocated by some commenters, to be inconsistent with the approach we adopt in this final rule, which requires measurement and use of each of the seven required benefits in Long-Term Regional Transmission Planning, and we are concerned that permitting the use of screens could undermine this requirement. We therefore do not allow transmission providers to use a screening approach when measuring the seven required benefits.

### 2. Required Benefits

#### a. The Seven Required Benefits

##### i. Benefit 1: Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement

###### (a) NOPR Description

740. The Commission described this benefit in the NOPR as the reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. The Commission stated that, recognizing that regional transmission planning could lead to the development of transmission facilities that span the service territories of multiple transmission providers, which in turn would obviate the need for transmission facilities that would otherwise be identified in

Interwest Initial Comments at 12-13; WATT Coalition Initial Comments at 7.

[1642] Clean Energy Buyers Initial Comments at 20-21.

multiple local transmission plans, the Commission has accepted accounting for such "avoided costs" as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO regions. [1643] The Commission noted that, in using this method, transmission providers in a transmission planning region determine the beneficiaries of a regional transmission facility or portfolio of facilities by identifying the local and regional transmission facilities that a new proposed regional transmission facility or portfolio of facilities would displace. The Commission described the method as defining the benefits of the regional transmission facility or facilities as the costs that transmission providers in the transmission planning region "avoid" because they no longer need to build the displaced local and regional transmission facilities. Further, the Commission stated that the method allocates costs among transmission providers whose local or regional transmission facilities the new proposed regional transmission facility or facilities would displace in proportion to their share of the total benefits (i.e., the total avoided costs). If the new proposed regional transmission facility or facilities do not displace any local or regional transmission facilities in existing local or regional transmission plans, the Commission discussed that the avoided cost method determines the benefits of the applicable facilities by considering the costs of local or regional transmission facilities that would otherwise be needed to meet the same need that the new proposed regional transmission facility will

[1643] NOPR, 179 FERC ¶ 61,028 at PP 189-190 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

meet.[1644] The Commission noted that, in calculating this benefit, transmission providers in each transmission planning region could first identify transmission facilities that could defer or replace an identified reliability transmission solution. Avoided cost benefits could be calculated by comparing the cost of transmission facilities required to address the reliability need without the proposed regional transmission facility to the cost of transmission facilities needed to address the reliability need assuming the regional transmission solution were in place.[1645]

741. The Commission noted that Benefit 1 could also include the separate benefits stream caused by a deferral of replacement of other transmission facilities through identification and selection of a transmission facility or facilities. This could be measured through calculation of the present value savings for the period of deferral of additional replacement transmission facilities multiplied by their estimated capital cost.[1646] The Commission also noted that a number of transmission providers already evaluate the avoided or deferred costs of reliability transmission projects. For example, SPP uses a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a potential reliability transmission facility. The costs of these avoided or

[1644] NOPR, 179 FERC ¶ 61,028 at P 190 (citing *S.C. Elec. & Gas Co.*, 143 FERC ¶ 61,058, at P 232 (2013)).

[1645] *Id.* P 191 (citing Brattle-Grid Strategies Oct. 2021 Report at 37).

[1646] *Id.* P 192.

delayed reliability transmission facilities are used to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.[1647] The Commission stated that transmission providers could also use avoided costs to calculate the benefits of replacing aging transmission facilities. The Commission provided NYISO as an example, which estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.[1648]

**(b) Comments**

742. A number of commenters support mandating consideration of Benefit 1.[1649] ACEG, for example, supports inclusion of this benefit, asserting that reliability considerations and replacing aging assets are responsible for almost all current

[1647] *Id.* P 193 (citing SPP, *SPP Benefit Metrics Manual*, SPP Engineering, at 15 (Nov. 6, 2020)).

[1648] *Id.* P 193 (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, at 114 (Sept. 15, 2015)).

[1649] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25 (including Benefit 1 in its recommended minimum set of benefit categories); Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Certain TDUs Reply Comments at 1-2; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11-13; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

transmission spending.[1650] However, MISO states that, when capturing avoided transmission investment benefits, care must be exercised to avoid the counting of benefits associated with facility overloads that are identified in reliability studies and directly addressed by regional transmission projects. MISO indicates that this approach is necessary because the adjusted production cost savings benefits already reflect the congestion associated with these facility overloads.[1651] Southern states that this benefit would likely prove workable under its non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of "avoided costs."[1652]

743. Several commenters oppose or express concerns with mandating consideration of Benefit 1.[1653] West Virginia Commission argues that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1654] Xcel states that benefit calculations can be different between the short-term regional transmission planning process and Long-Term Regional Transmission Planning and that, for example, it would likely be unreasonable to determine reliability benefits in

[1650] ACEG Initial Comments at 34-35.

[1651] MISO Initial Comments at 50.

[1652] Southern Initial Comments at 25.

[1653] Joint Consumer Advocates Initial Comments at 11; NARUC Initial Comments at 22; West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

[1654] West Virginia Commission Supplemental Comments at 4.

Long-Term Regional Transmission Planning using the avoided cost of local reliability solutions.[1655]

744. NARUC states that, while Benefit 1 seems capable of calculation, it carries with it a degree of risk if aging transmission infrastructure continues to be operated. For instance, NARUC indicates that some wildfires have been linked to deferred transmission maintenance of aging infrastructure.[1656] AEE responds by stating that the Commission should clarify: (1) its expectations regarding its calculation; and (2) that regional transmission built for inherently economic or public policy purposes has, when installed, avoided reliability cost benefits.[1657] AEE argues that calculating the benefits of avoided investment in reliability or replacement facilities should not create an environment for continuously putting "band aid" fixes on aging systems that should instead be replaced to ensure reliability and resilience.[1658]

### (c) Commission Determination

745. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement, in Long-Term Regional Transmission Planning. We adopt the NOPR's

[1655] Xcel Initial Comments at 13.

[1656] NARUC Initial Comments at 22.

[1657] AEE Reply Comments at 26 (citing NARUC Initial Comments at 22).

[1658] *Id.*

proposed description of Benefit 1 as the reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. We find that requiring the measurement and use of Benefit 1, as described, is necessary because Long-Term Regional Transmission Facilities may obviate or delay the need for reliability transmission facilities identified in the near term, or the need for later replacements of aging transmission infrastructure. Requiring transmission providers to measure and use the benefits associated with avoiding or delaying such transmission needs will help to ensure that, when conducting Long-Term Regional Transmission Planning, transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

746. We note that a number of transmission providers already evaluate avoided or deferred costs of reliability transmission facilities. ACEG states that Benefit 1 reflects that reliability considerations and replacing aging assets drive significant investment in transmission and account for almost all current transmission spending.[1659] SPP employs a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a potential reliability transmission facility, using the costs of these avoided or delayed reliability transmission facilities to determine the reliability benefit of the potential

[1659] ACEG Initial Comments at 34-35.

economic or Public Policy Requirements transmission facilities.[1660] Additionally, NYISO estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.[1661] We find that widespread use of this benefit contradicts West Virginia Commission's assertion that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance, as well as similar assertions by Xcel.[1662]

747. We agree with NARUC and AEE that continued operation of aging infrastructure can carry risks if it is not properly maintained.[1663] We note that nothing in this final rule restricts an incumbent transmission provider from developing a local transmission facility to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.[1664] Such a solution would not be subject to approval at the regional or interregional level where the transmission provider does not seek to have it selected as

[1660] NOPR, 179 FERC ¶ 61,028 at P 193 (citing SPP, *SPP Benefit Metrics Manual*, SPP Engineering, at 15 (Nov. 6, 2020)).

[1661] *Id.* (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, at 114 (Sept. 15, 2015)).

[1662] West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

[1663] AEE Reply Comments at 26 (citing NARUC Initial Comments at 22); NARUC Initial Comments at 22.

[1664] Order No. 1000, 136 FERC ¶ 61,051 at PP 262, 329.

a regional transmission facility for purposes of cost allocation.[1665] Moreover, nothing in this final rule requires transmission providers to keep transmission facilities in operation beyond their useful life. We emphasize that transmission providers can use Benefit 1 to calculate the costs that are avoided because replacements of local or regional transmission facilities are no longer needed, or may be deferred, when they are displaced by proposed new Long-Term Regional Transmission Facilities.

#### ii. Benefit 2(a): Reduced Loss of Load Probability or Benefit 2(b): Reduced Planning Reserve Margin

##### (a) NOPR Description

748. The Commission described this benefit in the NOPR as being measured in one of two ways: (a) using reduced loss of load probability *or* (b) reduced planning reserve margin. The Commission noted that, because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, a single transmission facility can either reduce loss of load events if the planning reserve margin is unchanged or allow for the reduction in planning reserve margins if loss of load events remain constant, but not both simultaneously.[1666]

749. The Commission described Benefit 2(a) in the NOPR as reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the

[1665] *Id.* P 384.

[1666] NOPR, 179 FERC ¶ 61,028 at P 194.

planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events.[1667] The Commission noted that transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period. The Commission noted that one example of how a reduction of loss of load probability benefit could be calculated can be found in a report by SPP's Metrics Task Force. The report proposes quantifying the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, obtaining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a transmission expansion.[1668]

750. The Commission described Benefit 2(b) in the NOPR as reduced planning reserve margin, or "the reduction in capital costs of generation needed to meet resource adequacy requirements (i.e., planning reserve margins) while holding loss of load probability

[1667] *Id.*

[1668] *Id.* P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review*, at 25 (Sept. 13, 2012)).

constant."[1669] The Commission stated that investments in transmission capacity can reduce the system-wide planning reserve margin requirement or the reserve margin requirement within individual resource adequacy zones of a transmission planning region, which can reduce the need for generation capital expenditures.[1670] The Commission also stated that it is important to note that, due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with loss of load probability, only one of these benefits should be calculated for a transmission investment, but not both simultaneously.[1671] The Commission noted that RTOs/ISOs have calculated the transmission benefits of reduced planning reserve margins. MISO, for example, calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, which reduced the need for future generation buildout to meet reserve requirements, by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of $1.0 to $5.1 billion in benefits over 10 years.[1672]

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[1669] *Id.* P 194.

[1670] *Id.* P 196.

[1671] *Id.*

[1672] *Id.* P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36-38 (Sept. 19 & 29, 2011)).

**(b) Comments**

751. A number of commenters support mandating consideration of Benefit 2(a).[1673] Some commenters discuss the manner in which this benefit should be calculated.[1674] ACEG and DC and MD Offices of People's Counsel note the importance of geographic diversity between transmission planning regions as an important consideration in evaluating this benefit.[1675] Specifically, ACEG states that it can be estimated using the value of lost load and generation capital cost savings due to lower needed planning reserve margins.[1676]

752. However, some commenters oppose or express concerns regarding mandating consideration of Benefit 2(a).[1677] NARUC states that transmission planners are likely already considering loss of load events in their evaluations of system expansions and that

[1673] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

[1674] *E.g.*, ACEG Initial Comments at 38-39.

[1675] ACEG Initial Comments at 35-38; DC and MD Offices of People's Counsel Initial Comments at 21-24.

[1676] ACEG Initial Comments at 38.

[1677] NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

whether such benefit, in isolation, is sufficient to recommend construction of a particular transmission project is a question best left to them and their states.[1678] West Virginia Commission argues that calculation of benefits from reduced loss of load probability requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1679] R Street states that Benefit 2(a) should be refined to the avoided value of lost load so that it is compatible with an economic assessment, while Illinois Commission asserts that the Commission should consider a more expansive definition of reduced loss of load probability composed of more than one metric, such as value of lost load, expected unserved energy, or a hybrid measure, that can serve as a supplement to loss of load expectation.[1680]

753. With respect to Benefit 2(b), a number of commenters support mandating consideration of this benefit.[1681] AEP recommends including Benefit 2(b) as a part of a

[1678] NARUC Initial Comments at 23.

[1679] West Virginia Commission Supplemental Comments at 4.

[1680] Illinois Commission Initial Comments at 14; R Street Initial Comments at 9.

[1681] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

combination of benefits.[1682] Pine Gate states that this proposed benefit is critical to address resource adequacy concerns, particularly where a transmission planning region relies heavily on a single generation type.[1683]

754. With respect to comments in opposition to Benefit 2(b), similar to its comments on Benefit 2(a) above, West Virginia Commission argues that calculation of benefits from reduced planning reserve margin requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1684]

**(c) Commission Determination**

755. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 2, in Long-Term Regional Transmission Planning. This benefit can be characterized and measured as Benefit 2(a), Reduced Loss of Load Probability, or as Benefit 2(b), Reduced Planning Reserve Margin, and we clarify that these are different methods for measuring the same underlying benefit. We find that requiring the measurement and use of this benefit is necessary because it reflects an important category of reliability benefits of Long-Term Regional Transmission Facilities. Because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, for purposes of Long-Term Regional Transmission Planning, transmission providers must either measure

[1682] AEP Initial Comments at 25.

[1683] Pine Gate Initial Comments at 37.

[1684] West Virginia Commission Supplemental Comments at 4.

reduced loss of load events by holding the planning reserve margin constant *or* measure the reduction in planning reserve margins by holding loss of load events constant but may not measure both simultaneously for purposes of using and measuring Benefit 2(a) or 2(b).

756. We adopt the NOPR's proposed description of Benefit 2(a) that describes Benefit 2(a), Reduced Loss of Load Probability, as the reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events. Benefit 2(a) measures reduced loss of load probability for resource adequacy planning, which typically includes the consideration of normal system conditions. One method of measuring a reduction in loss of load probability benefit is to quantify the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, determining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a Long-Term Regional Transmission Facility or a portfolio of Long-Term Regional Transmission Facilities.[1685]

[1685] NOPR, 179 FERC ¶ 61,028 at P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review*, at 25 (Sept. 13, 2012)).

757. Numerous commenters support mandating Benefit 2(a).[1686] We recognize commenter suggestions regarding the method for calculating this benefit, with some recommending consideration of geographic diversity between transmission planning regions[1687] and others recommending that the benefit be expressed in terms of the value of lost load.[1688] We agree that geographic diversity is an important consideration in evaluating the reduced loss of load probability method of calculating this benefit and find that the flexibility in measuring benefits that we provide to transmission providers under this final rule allows for this consideration. As to the suggestion by Illinois Commission and R Street that Benefit 2(a) should be expressed in terms of the value of lost load so that it can be expressed in terms of cost, we believe that either Benefit 2(a) or Benefit 2(b) are reasonable methods to calculate Benefit 2 and we reiterate that transmission providers can choose either method to calculate this benefit. We encourage transmission

[1686] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

[1687] ACEG Initial Comments at 35-38; DC and MD Offices of People's Counsel Initial Comments at 21-24.

[1688] Illinois Commission Initial Comments at 14 (suggesting alternatively that Benefit 2(a) be expressed in terms of expected unserved energy, or a hybrid measurement composed of more than one metric); R Street Initial Comments at 9 (stating that using value of lost load is compatible with an economic assessment).

providers to consider whether Benefit 2(a) or Benefit 2(b) is the most effective way to accurately reflect the benefits of a proposed Long-Term Regional Transmission Facility in their individual regions. As to NARUC's contention that the benefit of reducing the probability of loss of load events, in isolation, may be insufficient to support the development of a particular transmission project, while we are requiring transmission providers to use Benefit 2(a) or Benefit 2(b) to evaluate Long-Term Regional Transmission Facilities, we are not requiring transmission providers to base their evaluation on this single benefit—or any single benefit, for that matter—but rather on at least the range of benefits included in the required set of benefits that we adopt herein. Moreover, we are not requiring that transmission providers select any Long-Term Regional Transmission Facility.

758. As noted above, the NOPR proposed the following description of Benefit 2(b), "the reduction in capital costs of generation needed to meet resource adequacy requirements (i.e., planning reserve margins) while holding loss of load probability constant."[1689] We adopt the NOPR description in this final rule. We find that a lower planning reserve margin is another way to demonstrate a resource adequacy benefit. As we indicate above, due to the relationship between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with reduced loss of load probability, only one of these methods for calculating the benefit for a transmission investment can be used, but not both simultaneously. We find that Benefit 2(b) is one of

[1689] NOPR, 179 FERC ¶ 61,028 at P 194.

two ways to calculate reduced costs related to resource adequacy because Long-Term Regional Transmission Facilities can reduce the system-wide planning reserve margin requirements within individual resource adequacy zones of a transmission planning region and provide benefits by reducing the need for generation capital expenditures.

759. Many commenters support mandating consideration of Benefit 2(b). For example, DC and MD Offices of People's Counsel note that the benefit of a reduced reserve planning margin has been used in multiple cases.[1690] We also find that it is feasible for transmission providers to calculate the benefit of reduced planning reserve margins. We reiterate here the example of MISO, which calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, reducing the need for future generation investments to meet reserve requirements by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of $1.0 to $5.1 billion in benefits over 10 years.[1691]

[1690] DC and MD Offices of People's Counsel at 22-23 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36-38 (Sept. 19 & 29, 2011); SPP, *Benefits for the 2013 Regional Cost Allocation Review* (Sept. 13, 2012); *Investigation on Comm'n's Own Motion to Review18 Percent Planning Reserve Margin Requirement*, Docket No. 5-EI-141 (PSC REF# 102692), at 5 (Pub. Serv. Comm'n Wis. Oct. 9, 2008); SPP, *The Value of Transmission*, at 16 (Jan. 26, 2016); Midcontinent Independent System Operator, Inc., *MISO Value Proposition 2020: Forward View*, at 20-21 (June 2022); PJM Interconnection, L.L.C., *PJM Value Proposition*, at 2 (2019); Australian Energy Market Operator, *2022 Integrated System Plan*, at 64 (June 2022)).

[1691] NOPR, 179 FERC ¶ 61,028 at P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36-

We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,[1692] in non-RTO/ISO transmission planning regions.[1693]

760. Finally, we disagree with West Virginia Commission's claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1694] As noted above, there are multiple examples in the record of transmission providers that currently calculate these benefits. Because we find that transmission providers will be able to calculate either Benefit 2(a) or 2(b) and recognize the importance of accounting for Benefit 2 in Long-Term Regional Transmission Planning, we require transmission providers to measure and use Benefit 2.

### iii. Benefit 3: Production Cost Savings

#### (a) NOPR Description

761. The Commission described Benefit 3 in the NOPR as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as

38 (Sept. 19 & 29, 2011)).

[1692] *PacifiCorp*, 147 FERC ¶ 61,057 at PP 133-134, 141-143; *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314.

[1693] *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141-143.

[1694] West Virginia Commission Supplemental Comments at 4.

lower-cost suppliers set market clearing prices.[1695] The Commission stated that most regional transmission planning processes currently estimate production cost savings. Generally, within RTOs/ISOs, security-constrained production cost models simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints. The traditional method for estimating the changes in adjusted production costs associated with proposed transmission facilities (or portfolio of facilities) is to compare the adjusted production costs with and without those facilities. Analysts typically call the market simulations without the proposed transmission facilities the "Base Case" and the simulations with those facilities the "Change Case."[1696]

762. The Commission further explained that approaches used to calculate production cost savings vary. MISO uses production cost savings (adjusted for import costs and export revenues) to allocate the costs of its Market Efficiency Projects to cost allocation zones based on each zone's share of the total adjusted production cost savings.[1697] The Commission also explained, in contrast, that NYISO and PJM use reductions to load

[1695] NOPR, 179 FERC ¶ 61,028 at P 198 & n.333 (proposing to define this as adjusted production cost savings when the calculation is adjusted to account for purchases and sales outside the region).

[1696] NOPR, 179 FERC ¶ 61,028 at P 199.

[1697] NOPR, 179 FERC ¶ 61,028 at P 200 (citing MISO, FERC Electric Tariff, attach. FF, Benefit Metrics § (I)(A)(1) (33.0.0)).

energy payments (adjusted to reflect the reduced value of transmission congestion contracts) to allocate the costs of economic transmission facilities.[1698]

763. The Commission stated that non-RTO/ISO regions, without centrally organized energy markets, rely on other tools to perform analyses of production cost savings. For example, WestConnect's regional cost allocation method for regional transmission facilities driven by economic considerations identifies the benefits and beneficiaries of a proposed regional transmission facility or facilities by modeling the potential of the transmission facilities to support more economic bilateral transactions between generators and loads in the region. Specifically, WestConnect considers the transactions between loads and lower-cost generation that a proposed regional transmission facility could support and, accounting for the costs associated with transmission service, identifies the transactions that are likely to occur. WestConnect then estimates any resulting cost savings (in the form of reductions in production costs and reserve sharing requirements) and allocates the costs of the regional transmission facilities on that basis.[1699]

[1698] NOPR, 179 FERC ¶ 61,028 at P 200 & n.335 (citing *PJM Interconnection L.L.C.*, 142 FERC ¶ 61,214 at P 416; *N.Y. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,059, at PP 268, 269, n.516 (2013); NYISO, NYISO Tariffs, OATT, attach. Y, § 31.5 (Cost Allocation and Cost Recovery) (30.0.0), § 31.5.4.3.2.) ("For high voltage economic transmission facilities, PJM allocates 50% of the costs in accordance with its economic analysis and allocates the other 50% of the costs on a load-ratio share basis.").

[1699] NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314).

**(b) Comments**

764. A number of commenters support mandating consideration of this benefit.[1700] AEP recommends including Benefit 3 as a part of a combination of benefits.[1701] According to TAPS, all of the RTOs/ISOs already consider production cost savings; TAPS argues that the Commission should require transmission providers in non-RTO/ISO transmission planning regions to consider them as well.[1702] Indicated PJM TOs state that this benefit is one of the main benefits that will drive the selection of transmission facilities in PJM.[1703]

765. Some commenters opine on how to calculate this benefit.[1704] ACEG states that production cost savings should include fuel and variable operating cost savings,

[1700] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Certain TDUs Reply Comments at 1-2; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Joint Consumer Advocates Initial Comments at 11; New Jersey Commission Initial Comments at 13-14 (including reduced production costs during transmission outages, extreme events, and higher than normal load conditions in Benefit 3); Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; TAPS Initial Comments at 14; US DOE Initial Comments at 31-32.

[1701] AEP Initial Comments at 25.

[1702] TAPS Initial Comments at 14.

[1703] Indicated PJM TOs Initial Comments at 17.

[1704] ACEG Initial Comments at 40; DC and MD Offices of People's Counsel

adjustments for imports from neighboring transmission planning regions, reduced costs of cycling power plants, reduced amounts and costs of operating reserves and other ancillary services, and mitigation of reliability-must-run conditions.[1705] Likewise, DC and MD Offices of People's Counsel state that production cost savings should include ancillary service cost savings.[1706] MISO notes that, in addition to evaluating production cost savings under normal patterns of renewable dispatch and load, transmission providers can analyze production cost savings that accrue during transmission outages using historical sampling or statistical modeling of transmission outage patterns.[1707] MISO TOs state that its process to evaluate Multi-Value Projects considers production cost savings that can be realized through reduced transmission congestion and transmission energy losses, capacity loss savings, capacity savings, long-term cost savings, and "any other financially quantifiable benefit."[1708]

766. Some commenters oppose or express concerns regarding mandating consideration of production cost savings.[1709] For example, Southern states that considering production

Initial Comments at 25; GridLab Initial Comments at 26-27; MISO Initial Comments at 49-50.

[1705] ACEG Initial Comments at 40.

[1706] DC and MD Offices of People's Counsel Initial Comments at 25.

[1707] MISO Initial Comments at 49-50.

[1708] MISO TOs Initial Comments at 21 (citing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, attach. FF (90.0.0), § II.C.5).

[1709] Mississippi Commission Initial Comments at 35-36; North Carolina Commission and Staff Initial Comments at 7; Pacific Northwest Utilities Initial

cost savings could result in the double-counting of benefits in its footprint by, for example, making generation pricing/cost decisions that have already been made or will ultimately be made in integrated resource planning or request for proposal processes.[1710] Relatedly, North Carolina Commission and Staff state that requiring consideration of production cost savings would conflict with state-jurisdictional resource decisions.[1711] Mississippi Commission contends that this benefit may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.[1712] PJM Market Monitor states that in PJM, comparing production cost savings across different gas prices and different generation resource capacity may not provide meaningful guidance as to the benefits of a transmission facility beyond that currently provided by satisfying reliability criteria because of potentially inaccurate forecasts for key values.[1713] Pacific Northwest Utilities assert that this benefit is not easily quantifiable.[1714]

Comments at 9; PJM Market Monitor Initial Comments at 5; Southern Initial Comments at 26.

[1710] Southern Initial Comments at 26 (citing Southern Initial Comments Ex. 1, ¶¶ 8, 15).

[1711] North Carolina Commission and Staff Initial Comments at 7.

[1712] Mississippi Commission Initial Comments at 36.

[1713] PJM Market Monitor Initial Comments at 5.

[1714] Pacific Northwest Utilities Initial Comments at 9.

### (c) Commission Determination

767. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 3, Production Cost Savings, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 3 as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices. We find that requiring the use of Benefit 3 is necessary because Long-Term Regional Transmission Facilities could result in savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production. We further find that, absent a requirement for transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

768. We do not require a standardized method for measuring production cost savings, and, consistent with this approach, we decline commenter requests to specify the exact types of cost savings for which transmission providers must account when measuring this

benefit.[1715] As the Commission stated in the NOPR,[1716] different transmission planning regions have different approaches toward the calculation of this benefit, and this final rule provides flexibility for transmission providers in developing the method that they use to measure production cost savings, consistent with the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning described above.

769. We note that Benefit 3 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 3 and Benefit 6, as described in this final rule, both measure production cost savings (including savings that occur during generation outage contingencies), the system conditions used in calculating each benefit are distinct. For example, Benefit 6 can include higher electricity demand, forecast errors, volatile production costs, and a more expansive set of generation outages such as unplanned generation outages due to extreme weather. And as we discuss below in the context of Benefit 5, because Benefit 3, Production Cost Savings, as described in this rule, does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well.

[1715] *See* ACEG Initial Comments at 40; DC and MD Offices of People's Counsel Initial Comments at 25; GridLab Initial Comments at 26-27; MISO Initial Comments at 49-50.

[1716] NOPR, 179 FERC ¶ 61,028 at PP 200-201.

770. We also do not believe that requiring transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning will, as Southern suggests, result in double-counting of benefits because such benefits are also considered in state resource planning. While we acknowledge that integrated resource planning processes, where they exist, may consider similar benefits compared to those required by this final rule, the consideration of benefits in a state-jurisdictional process does not result in the double-counting of benefits within any Commission-jurisdictional transmission planning process. Because practices affecting rates, terms, and conditions for interstate transmission service are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional regional transmission planning processes result in rates that are just and reasonable and not unduly or discriminatory. To this end, this final rule is focused on ensuring that, when conducting Long-Term Regional Transmission Planning, transmission providers consider the broader set of benefits provided by Long-Term Regional Transmission Facilities so that they may determine whether to select such facilities as the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs.

771. Pacific Northwest Utilities assert that production cost savings are not easily quantifiable.[1717] We acknowledge that there are some challenges associated with measuring this benefit, but we conclude that it is nonetheless necessary to require such measurement in order to ensure that transmission rates are just, reasonable, and not

[1717] Pacific Northwest Utilities Initial Comments at 9.

unduly discriminatory or preferential. We also note that there is an abundance of examples of how transmission providers can measure this benefit. Production cost savings are used extensively in many transmission planning regions, including MISO, NYISO, PJM, SPP, CAISO, ISO-NE, NorthernGrid, and WestConnect.[1718] We believe that transmission providers are capable of measuring production cost savings given that this benefit has been used as a metric in transmission planning for decades.

772. In response to North Carolina Commission and Staff's contention that requiring consideration of production cost savings conflicts with state-jurisdictional resource decisions,[1719] we find that North Carolina Commission and Staff have failed to explain why there may be a conflict. As noted in the Need for Reform, there are deficiencies in the Commission's existing transmission planning and cost allocation requirements, including that they fail to require transmission providers to adequately consider the

[1718] *See* NOPR, 179 FERC ¶ 61,028 at PP 200-201; Brattle-Grid Strategies Oct. 2021 Report at 31; ISO New England, Inc., *Transmission Planning: Maintaining Power System Reliability Amid Change*, https://www.iso-ne.com/system-planning/transmission-planning (last visited Mar. 25, 2024); NorthernGrid, *Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, 2 (Sept. 21, 2022), https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf; The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, 31 (July 2013), https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf (noting that in the Western Electricity Coordinating Council (WECC), whose service area includes one RTO (CAISO) and three non-RTO regions (ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect) production costs simulations are used to calculate the energy costs savings of transmission projects in WECC's long-term transmission planning studies).

[1719] North Carolina Commission and Staff Initial Comments at 7.

broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. We are concerned that failing to adequately identify and consider the benefits, including production cost benefits, of such transmission facilities may lead to relatively inefficient and less cost-effective transmission development. Additionally, as described above in the Categories of Factors section, transmission providers must incorporate, and not discount, state-jurisdictional resource decisions, such as integrated resource plans, into all Long-Term Scenarios to identify Long-Term Transmission Needs. Therefore, we believe that requiring transmission providers to measure production cost savings will not conflict with state-jurisdictional resource decisions, because the effects of such resource decisions on Long-Term Transmission Needs must be fully accounted for in all Long-Term Scenarios, which are used to help identify more efficient or cost-effective regional transmission solutions within the Commission-jurisdictional regional transmission planning process. Moreover, as discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section of this final rule, nothing in this final rule conflicts with or infringes on the states' reserved authority under FPA section 201.

773. We disagree with Mississippi Commission's assertion that production cost savings may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.[1720] Financial transmission rights are required in RTO/ISO markets and allow the market participant that owns the right to mitigate the congestion charge

[1720] Mississippi Commission Initial Comments at 36.

along an existing transmission path for the capacity of that path.[1721] A new transmission facility could reduce congestion and allow that market participant to purchase more electricity, exceeding the capacity of the transmission path for the financial transmission right, at a lower price. This reduced congestion allows for load to access lower cost resources, and results in more efficient dispatch of resources and, thus, provides avoided production cost benefits that are distinct from the avoided congestion charges associated with financial transmission rights.

774. We recognize the PJM Market Monitor's concern regarding the potential for inaccurate forecasts of key inputs to the calculation of production cost savings.[1722] However, we conclude that this potential concern does not outweigh the value of measuring and using this benefit, as demonstrated by long-standing use of this benefit within PJM and other transmission planning regions, including all RTOs/ISOs and some non-RTO/ISO regions. Moreover, as noted in the Long-Term Scenarios section of this final rule, the use of Long-Term Scenarios in Long-Term Regional Transmission Planning mitigates such uncertainty in transmission planning outcomes. Specifically, comparing the production cost savings, as well as the other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission

[1721] *Long-Term Firm Transmission Rights in Organized Elec. Mkts.*, Order No. 681, 116 FERC ¶ 61,077, at PP 5, 19-21, *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006), *order on reh'g & clarification*, Order No. 681-B, 126 FERC ¶ 61,254 (2009).

[1722] PJM Market Monitor Initial Comments at 5.

Planning, provided by Long-Term Transmission Facilities across three distinct Long-Term Scenarios should help to address the uncertainty noted by the PJM Market Monitor.

### iv. Benefit 4: Reduced Transmission Energy Losses

#### (a) NOPR Description

775. The Commission described this benefit in the NOPR as reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads.[1723]

776. The Commission explained that production cost savings metrics used today typically exclude reduced transmission energy losses and three other production cost savings-related benefits proposed in the NOPR. The Commission also stated that including those additional proposed benefits can produce a more robust set of congestion and production cost benefits that can be quantified and integrated into the method for calculating production cost savings and, therefore, help to ensure that more efficient or cost-effective transmission facilities are selected through Long-Term Regional Transmission Planning.[1724]

777. The Commission noted that to measure reduced transmission energy losses, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges. For example,

[1723] NOPR, 179 FERC ¶ 61,028 at P 202.

[1724] *Id.* P 203.

ATC measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates using the marginal loss component from the PROMOD[1725] electric market simulation software simulations for the Paddock-Rockdale 345 kV Access Project,[1726] which produced cost reduction benefits using adjusted production cost analysis. Also, SPP's analysis for its Regional Cost Allocation Review process estimated energy loss reductions through post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.[1727]

**(b) Comments**

778. A number of commenters support mandating consideration of Benefit 4.[1728] While not favoring a benefits measurement requirement, Southern states that this benefit would

[1725] PROMOD is a generator and portfolio modeling system. Hitachi Energy: PROMOD, (last visited Apr. 2024).

[1726] NOPR, 179 FERC ¶ 61,028 at P 204 & n.338 (citing ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, app. C, Ex. 1, at 34-38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007)).

[1727] SPP, *SPP Regional Cost Allocation Review Report for RCAR II*, at 56, 64 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

[1728] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 13-14; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

likely prove workable under Southern's non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of reduced transmission energy losses.[1729]

779. Several commenters comment on the manner in which Benefit 4 should be calculated.[1730] ACEG states that this benefit has been calculated in various studies.[1731]

780. West Virginia Commission opposes the use of Benefit 4, arguing that the calculation of benefits from reduced transmission losses requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.[1732]

### (c) Commission Determination

781. We adopt the NOPR proposal, with modification, to require transmission providers to measure and use Benefit 4, Reduced Transmission Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 4, as modified, as the reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads.

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[1729] Southern Initial Comments at 25.

[1730] ACEG Initial Comments at 41; NARUC Initial Comments at 23 (noting that advanced technologies also provide this benefit and should be preferred over greenfield construction); Utah Division of Public Utilities Initial Comments at 8.

[1731] ACEG Initial Comments at 41 (citing ATC, Planning Analysis of the Paddock-Rockdale Project, app. C Ex. 1, at 34-38 (Wisc. Pub. Serv. Docket No. 137-CE-149); SPP, *Regional Cost Allocation Review Report for RCAR II*, at 5 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf).

[1732] West Virginia Commission Supplemental Comments at 4.

We find that requiring the measurement and use of Benefit 4 in Long-Term Regional Transmission Planning is necessary because reduced energy losses are widely understood to be a benefit of transmission facilities.[1733] As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

782. We recognize that there are multiple ways for transmission providers to measure reduced transmission energy losses.[1734] We note that this final rule does not require transmission providers to adopt any single method to measure reduced transmission energy losses. As described in the NOPR, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges.[1735] Transmission providers could also follow the example of

[1733] *See* Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 19-20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11-14; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 38-41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

[1734] *See, e.g.*, ACEG Initial Comments at 41 (citing studies in which Benefit 4 has been calculated).

[1735] NOPR, 179 FERC ¶ 61,028 at P 204.

ATC, which measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates provided by the PROMOD electric market simulation software.[1736] Similarly, SPP estimates energy loss reductions through its Regional Cost Allocation Review process by post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.[1737]

783. Because we find that transmission providers have multiple ways of calculating the benefit of reduced transmission energy losses, as well as record evidence demonstrating that the calculation of Benefit 4 is either already considered or is feasible in multiple transmission planning regions, we disagree with West Virginia Commission's claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1738] We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.[1739]

[1736] ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, app. C Ex. 1, at 34-38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[1737] SPP, *Regional Cost Allocation Review Report for RCAR II*, at 56, 64 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

[1738] West Virginia Commission Supplemental Comments at 4.

[1739] *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141-143.

### v. Benefit 5: Reduced Congestion Due to Transmission Outages

#### (a) NOPR Description

784. The Commission described Benefit 5 in the NOPR as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect transmission outages, planned or unplanned.[1740] The Commission noted that transmission providers could measure this benefit, for example, by either building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by inducing system constraints more frequently. One application of this approach is SPP's Regional Cost Allocation Review process, which, inter alia, measured the benefits of reducing congestion resulting from transmission outages. In this process, SPP modeled outage events and new constraints based on these outages in PROMOD for a 2025 case year, and then conducted PROMOD simulations to calculate adjusted production cost savings for a base case and the change case including the transmission line.[1741]

[1740] NOPR, 179 FERC ¶ 61,028 at P 205 & n.340 (citing Brattle-Grid Strategies Oct. 2021 Report at 79).

[1741] *Id.* P 205 & n.341 (citing SPP, Inc., *Regional Cost Allocation Review Report for RCAR II*, at 51-52 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf. To estimate incremental savings associated with mitigation of transmission outage costs, SPP

**(b) Comments**

785. A number of commenters support mandating consideration of Benefit 5.[1742] While Southern does not support a requirement to use this or other benefits, it states that this benefit—which Southern understands as "operational flexibility"—could be explored for potential adoption in its footprint.[1743]

786. A few commenters opine on how to calculate the benefit of reduced congestion due to transmission outages.[1744] ACEG states that most transmission planning models ignore unplanned transmission outages that are likely to occur during extreme weather events, which ACEG claims will underestimate the value of Benefit 5.[1745] Similarly, DC

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analyzed outage cases in PROMOD for the 2025 study year. SPP developed cases based on 12 months of historical SPP transmission data. SPP said that because of the high volume of historical transmission outage data (approximately 7,000 outage events) and based on the expectation that many outages would not lead to significant increases in congestion, SPP only modeled a subset of outage events. The events selected were those expected to create significant congestion and met at least one of three conditions. *Id.* at 51.)

[1742] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

[1743] Southern Initial Comments at 25.

[1744] ACEG Initial Comments at 41-42; DC and MD Offices of People's Counsel Initial Comments at 25-26.

[1745] ACEG Initial Comments at 41.

and MD Offices of People's Counsel argue that, because unplanned transmission outages cause a significant portion of congestion costs, calculation of this benefit should account for such outages.[1746]

787. Some commenters oppose mandating consideration of Benefit 5.[1747] AEP argues that reduced congestion due to transmission outages is of lesser importance and does not need to be in the required minimum set of benefits.[1748] NARUC states that benefits associated with new construction to alleviate congestion is already a planning consideration.[1749] Pacific Northwest Utilities and West Virginia Commission assert that this benefit is not easily quantifiable.[1750] Idaho Power states that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion.[1751]

### (c) Commission Determination

788. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 5, Reduced Congestion Due to Transmission Outages, in Long-Term Regional Transmission

[1746] DC and MD Offices of People's Counsel Initial Comments at 25-26.

[1747] AEP Initial Comments at 27-28; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1748] AEP Initial Comments at 27.

[1749] NARUC Initial Comments at 23.

[1750] Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1751] Idaho Power Initial Comments at 8.

Planning. We adopt the NOPR's proposed description of Benefit 5 as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. We find that requiring the measurement and use of Benefit 5, as described, is necessary because reduced congestion due to transmission outages is widely understood to be a benefit of transmission facilities.[1752] As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

789. We also find that consideration of Benefit 5 is necessary because most current production cost simulations only consider generation outages—both planned generation outages and random distributions of unplanned generation outages; by contrast, production cost simulations do not typically address transmission outages, either planned or unplanned. Given that transmission facilities can provide benefits by reducing production costs during both generation outages and transmission outages, we find that it

[1752] *See* Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

is necessary for transmission providers to measure and use production cost savings during both generation outages and transmission outages in Long-Term Regional Transmission Planning. Because Benefit 3, Production Cost Savings, as described in this rule does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 5 and Benefit 6 both measure the benefit of reduced congestion due to transmission outages, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages such as unplanned outages due to extreme weather.

790. For the reasons stated above, we disagree with AEP's arguments that reduced congestion due to transmission outages is less important than other benefits and thus should not be required.[1753] And while some commenters object to consideration of reduced congestion due to transmission outages as a benefit on the grounds that this benefit is not easily quantifiable,[1754] we believe this benefit is merely another variant in production cost savings modeling that we already require for other benefits, such as Benefits 3 and 4.

[1753] AEP Initial Comments at 27.

[1754] *See* Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

### vi. Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions

#### (a) NOPR Description

791. The Commission described the benefit of mitigation of extreme events and system contingencies in the NOPR as reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies.[1755] These benefits include reduced production costs during extreme events facilitated by a more robust transmission system that reduces high-cost generation and emergency procurements necessary to support the system.[1756] The Commission noted that transmission providers can measure benefits from the mitigation of extreme events and system contingencies by calculating the probability-weighted production cost savings through production cost simulation for a set of extreme historical market conditions. The Commission provided as one example CAISO's analysis of Devers-Palo Verde Line No. 2, where CAISO modeled several contingencies to determine the value of the line during high-impact, low-probability events and, as another example, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line. ATC found that probability-weighted savings from reducing production and power

[1755] NOPR, 179 FERC ¶ 61,028 at P 206.

[1756] *Id.*

purchase costs during a number of simulated extreme events offset 20% of total project costs.[1757] The Commission also noted that a study found development of an additional 1,000 MW of transmission capacity into Texas would have fully paid for itself over four days during Winter Storm Uri and the same into MISO would have saved $100 million during the same time period.[1758]

792. Separately, the Commission described the benefit of mitigation of weather and load uncertainty in the NOPR as reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.[1759] The Commission stated that this is beyond the effects of extreme weather described above and may account for, for example, regional and sub-regional load variances that will occur due to changing weather patterns.[1760] The Commission provided, as one example, simulations that ERCOT performed for normal loads, higher-than-normal loads, and lower-than-normal

[1757] *Id.* P 207 & n.342 (*Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project*, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007)) & n.343 (ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, app. C, Ex. 1, at 4, 50-53 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007)).

[1758] *Id.* P 207 & n.344 (M. Goggin, Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2020)).

[1759] *Id.* P 208.

[1760] *Id.*

loads for a Houston import project, which showed increased benefits with a probability-weighted average for all three simulated load conditions.[1761]

**(b) Comments**

793. A number of commenters support mandating consideration of the benefit of mitigation of extreme events and system contingencies.[1762] For instance, Grid United states that extreme weather conditions significantly affect the electric grid and that requiring transmission providers to consider transmission projects based on their ability to mitigate extreme weather events will enhance resilience.[1763] ACEG and DC and Maryland Offices of People's Counsel state that consideration of the benefit of mitigation of extreme events and system contingencies is merited given "the hundreds of millions of dollars that would have been saved if transmission capacity had been greater during a

[1761] *Id.* P 209 & n.345 (citing ERCOT, *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting*, at 10 (Mar. 4, 2011). The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios).

[1762] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; ACORE Supplemental Comments at 1; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; PJM Initial Comments at 94 (in combination with Benefit 7, noting that significant stakeholder engagement is needed to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32; US Senator Schumer Supplemental Comments at 2-3.

[1763] Grid United Initial Comments at 3.

number of actual severe weather episodes."[1764] Clean Energy Associations assert that transmission providers should not calculate benefits solely based on average system conditions, as transmission investments can provide significant benefits during abnormal or extreme conditions or events.[1765]

794. Some commenters comment on the manner in which the benefit of mitigation of extreme events and system contingencies should be calculated.[1766] ACEG states that the benefit of mitigation of extreme events and system contingencies can be calculated by retrospective analysis or probabilistically. Additionally, ACEG recommends that the Commission require transmission providers to include avoided scarcity pricing, storm hardening and wildfire resilience, grid strength, and increased fuel diversity and system flexibility in addition to production cost savings when calculating the benefit of mitigation of extreme events and system contingencies.[1767] Similarly, DC and MD Offices of People's Counsel assert that the benefit of mitigation of extreme events and system contingencies should include resilience benefits such as storm and wildfire

[1764] ACEG Initial Comments at 43 & n.119; DC and Maryland Offices of People's Counsel Initial Comments at 26-27 & n.65 (both citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (Jul. 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf).

[1765] Clean Energy Associations Initial Comments at 21.

[1766] ACEG Initial Comments at 43; Clean Energy Associations Initial Comments at 21; DC and MD Offices of People's Counsel Initial Comments at 26-27; MISO Initial Comments at 51; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9.

[1767] ACEG Initial Comments at 43-44.

hardening, fuel diversity, and system flexibility, as well as reduced prices to consumers given that many regions set scarcity prices at values higher than generator production costs.[1768]

795. A number of commenters also support mandating consideration of the benefit of mitigation of weather and load uncertainty.[1769] Some commenters comment on the manner in which the benefit of mitigation of weather and load uncertainty should be calculated.[1770] GridLab posits that mitigation of weather and load uncertainty should only be included in the context of planning and operating reserves because "the cost to system operators of mitigating uncertainty is [the same as] the cost of holding additional reserves."[1771]

[1768] DC and MD Offices of People's Counsel Initial Comments at 26-27.

[1769] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; PJM Initial Comments at 94 (in combination with Benefit 6, noting that significant stakeholder engagement would be necessary to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31-32.

[1770] ACEG Initial Comments at 44; GridLab Initial Comments at 26; NARUC Initial Comments at 23.

[1771] GridLab Initial Comments at 26.

796. Other commenters oppose mandating consideration of the benefit of mitigation of extreme events and system contingencies, arguing that it is challenging to quantify and that its calculation entails subjective judgment.[1772] Louisiana Commission states that the value of mitigating extreme weather events can vary significantly across transmission planning regions and states. Louisiana Commission opposes any extreme weather benefit category that would result in the assignment of costs of transmission hardening projects to Louisiana ratepayers from which they do not benefit. Louisiana Commission further states that any analysis of this benefit should be limited to sensitivities.[1773]

797. Some commenters oppose mandating consideration of the mitigation of weather and load uncertainty.[1774] AEP states that this benefit should not be included in the minimum set of benefits because it is of lesser importance than other benefits described in the NOPR.[1775] NRECA argues that quantifying this benefit requires subjective judgment.[1776] According to Pacific Northwest Utilities, this benefit accrues to generation and load-serving entities, not to transmission providers.[1777]

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[1772] NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1773] Louisiana Commission Initial Comments at 18-19.

[1774] AEP Initial Comments at 27; NARUC Initial Comments at 23; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9.

[1775] AEP Initial Comments at 27.

[1776] NRECA Initial Comments at 45.

[1777] Pacific Northwest Utilities Initial Comments at 9.

798. NARUC states that the benefits of mitigation of extreme events, system contingencies, weather, and load uncertainties may be more appropriate for consideration in interregional transmission planning, depending on the size of the transmission planning region. While NARUC states that mitigation of such contingencies is among the soundest reasons for Interregional Transfer Capability planning, it also notes that in regions with a large footprint (e.g., PJM, MISO) it may be possible to assess these resilience benefits in the regional transmission planning process.[1778]

799. MISO states that the treatment of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty as economic benefits differ only to the degree at which production cost savings are realized. MISO also states that "mitigation of extreme events" may be represented as a reliability benefit where a value of outage costs can be used to monetize the benefits of mitigating the risk of load shedding.[1779] PJM suggests that the Commission should consolidate the benefits of mitigation of extreme events and system contingencies and the benefits of mitigation of weather and load uncertainty into a single enhanced reliability benefit that would evaluate the ability of grid enhancements to serve load reliably under extreme events and vulnerabilities.[1780] MISO and NARUC state that their comments regarding mitigation of

[1778] NARUC Initial Comments at 21, 23.

[1779] MISO Initial Comments at 51.

[1780] PJM Initial Comments at 94.

extreme events and system contingencies are equally applicable to mitigation of weather and load uncertainty.[1781]

### (c) Commission Determination

800. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Rule Benefit 6, mitigation of extreme weather events and unexpected system conditions, in Long-Term Regional Transmission Planning. The revised Final Rule Benefit 6 modifies and combines two of the benefits proposed in the NOPR: (1) mitigation of extreme events and system contingencies (NOPR Benefit 6) and (2) mitigation of weather and load uncertainty (NOPR Benefit 7).[1782] In combining these two proposed NOPR benefits, we modify the description of NOPR Benefit 6 and describe Final Rule Benefit 6 as reduced production costs and reduced loss of load (or emergency procurements necessary to support the system), including due to increased Interregional Transfer Capability, during extreme weather events and unexpected system conditions, such as unusual weather conditions or fuel shortages that result in multiple concurrent and sustained generation and/or transmission outages. The description of Final Rule Benefit 6 that we adopt in this final rule includes three additional modifications to the NOPR proposals describing NOPR Benefit 6 and NOPR Benefit 7. First, we require transmission providers to

[1781] MISO Initial Comments at 51; NARUC Initial Comments at 23.

[1782] NOPR, 179 FERC ¶ 61,028 at PP 206-207 (NOPR Benefit 6), 208-209 (NOPR Benefit 7).

measure, as part of Benefit 6,[1783] the benefits of reduced loss of load (not only reduced production costs). Second, we require transmission providers, as part of Benefit 6, to account for both extreme weather events and unexpected system conditions when transmission facilities have particularly high value. The unexpected system conditions can include, for example, system contingencies in the form of generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors. Third, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility during an extreme weather event or unexpected system condition that results in multiple and concurrent sustained generation and/or transmission outages.

801. We find that requiring the measurement and use of Benefit 6 in Long-Term Regional Transmission Planning is necessary because Long-Term Regional Transmission Facilities could result in reduced production costs and reduced loss of load (or reduced emergency procurements necessary to support the system), including reductions due to increased Interregional Transfer Capability, and improved performance during extreme weather events and unexpected system conditions. Further, the benefit of mitigation of high production costs resulting from extreme weather events and unexpected system conditions can be economically significant. A relatively few numbers of hours could

[1783] Throughout this final rule, "Benefit 6" refers to "Final Rule Benefit 6" unless preceded by "NOPR."

represent a large share of the total benefit of reduced congestion costs that a Long-Term Regional Transmission Facility provides.[1784] We also find that it is critical for transmission providers to measure and use Benefit 6 given that extreme weather events and unexpected system conditions have significantly and increasingly affected the reliable operation of the electric grid. As the Commission has previously noted, extreme weather events have occurred with greater frequency in recent years, leading to load shed events that present an unacceptable risk to life and have an extreme economic impact.[1785] By requiring the use of Benefit 6, we ensure that transmission providers measure and use the benefit of Long-Term Regional Transmission Facilities under these conditions when performing Long Term Regional Transmission Planning. Further, by requiring use of Benefit 6, we enable transmission providers to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

802. Regarding the first modification listed above, we require transmission providers to measure, as part of Benefit 6, reduced loss of load (or reduced emergency energy procurement to avoid loss of load), not only reduced production costs. We find it necessary to include reduced loss of load because Long-Term Regional Transmission Facilities can provide benefits by improving reliability during extreme weather events

[1784] *E.g.*, ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[1785] *See* Order No. 896, 183 FERC ¶ 61,191 at P 2; Order No. 897, 183 FERC ¶ 61,192 at PP 21-22.

and unexpected system conditions,[1786] which can be significant given the high cost and risk to life during periods with insufficient generation to meet system load. An example of how a reduction in loss of load could be measured is by quantifying the reduction in expected unserved energy but for the Long-Term Regional Transmission Facility during an extreme weather event or unexpected system conditions, determining the value of lost load, and multiplying these two values to obtain a monetary value.[1787]

803. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use, because transmission providers must model different system conditions (extreme weather events and unexpected system conditions) when measuring Benefit 6. Specifically, Benefit 2(a) measures reduced loss of load probability in the context of the system conditions used for resource adequacy planning, which typically includes consideration of normal system conditions and may vary by region. In contrast, Benefit 6 measures reduced loss of load for specific extreme weather events and unexpected system conditions identified by the transmission providers.[1788] Additionally,

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[1786] PJM Initial Comments at 94; MISO Initial Comments at 12-13; Order No. 897, 183 FERC ¶ 61,192 at PP 6-12.

[1787] *E.g.*, MISO, *LRTP Tranche 2 Business Case Benefit Metrics*, 6-7 (Aug. 31, 2023), https://cdn.misoenergy.org/20230831%20LRTP%20Workshop%20Item%2002%20Business%20Case%20Metrics%20Development630034.pdf.

[1788] Benefit 2(b), which measures the benefit of reduced planning reserve margin, is also used in the context of resource adequacy planning. We do not allow transmission providers to measure Benefit 6 in terms of reduced planning reserve margin because system planners do not always model extreme weather events or unexpected system conditions when establishing the planning reserve margin used for resource adequacy purposes. In contrast, reduced loss of load can be measured for any system condition,

while Benefit 3 and Benefit 6 both measure production cost savings, the system conditions used to measure Benefit 6 can include higher electricity demand, volatile production costs, and a more expansive set of generation outages, such as unplanned generation outages due to extreme weather. Similarly, Benefit 5 and Benefit 6 both measure the benefits of reduced congestion due to transmission outages; however, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages, such as unplanned transmission outages due to extreme weather.

804. Regarding the second modification listed above, we require transmission providers, as part of Benefit 6, to account for mitigation of unexpected system conditions during periods when transmission facilities have particularly high value, not only during extreme weather events. We recognize that unexpected system conditions can create periods when Long-Term Regional Transmission Facilities have particularly high value because of, for example, generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors.[1789] Limited resource

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even those conditions that are not used for resource adequacy planning.

[1789] *See, e.g.*, ACEG Initial Comments at 42-45 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System* (Oct. 14, 2020), https://open.bu.edu/handle/2144/41451; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, 2, 34, 78, 85-86, 99 (2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-TransmissionPlanning-Report_v2.pdf); DC and MD Offices of People's Counsel Initial Comments at 28 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, *BU-ISE* (Oct. 14, 2020), https://open.bu.edu/handle/2144/41451); US Senator Schumer Supplemental Comments at 2-3 (citing Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was*

availability, or limited system flexibility, can make it challenging for system operators to immediately address these unexpected system conditions, and Long-Term Regional Transmission Facilities that provide benefits under Benefit 6 will equip system operators with more options to manage the worst-case outcomes. These high-value periods of unexpected system conditions, while infrequent and not necessarily during extreme weather events, may account for a large share of the potential value of a Long-Term Regional Transmission Facility.[1790] We require transmission providers to account for circumstances that contribute to these infrequent and high-value periods specific to their transmission planning region when measuring Benefit 6. Transmission providers may, for example, identify historical periods when significant transmission congestion was due to certain conditions (e.g., generators being unavailable due to a forecast error), then model those conditions in each Long-Term Scenario.[1791] Therefore, we require

*Higher Last Year than at Any Point in the Last Decade*, 3-6 (Feb. 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf); US Senator Whitehouse Supplemental Comments at 2 (referencing outages related to extreme events having costs, including economic costs of in the billions of dollars from elevated energy costs).

[1790] LBNL Aug. 2022 Transmission Value Study at 33 (stating that the majority of transmission value estimated occurs during "extreme" conditions that fall outside of the 171 designated extreme weather event days between 2012 and 2021); Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade*, 3-6 (Feb. 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.

[1791] Alternatively, transmission providers may, for example, use probabilistic transmission planning methods to account for infrequent and high-value periods.

transmission providers to use not only information from modeling extreme weather events but also information from additional modeling that accounts for unexpected system conditions, as part of Benefit 6. To avoid double-counting of similar circumstances, transmission providers must account for extreme weather events and unexpected system conditions that are separate and distinct such that the benefits of mitigating each system condition can be combined into a single benefit measure.

805. Finally, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages. As discussed above, we find that Long-Term Regional Transmission Facilities can increase Interregional Transfer Capability by changing the topology of the transmission system.[1792] Further, we find that the benefits of mitigating extreme weather events and unexpected system conditions due to increased Interregional Transfer Capability provided by Long-Term Regional Transmission Facilities can be significant.[1793] To comply with this requirement, transmission providers must include in the modeling they use to measure Benefit 6 any increase in Interregional

[1792] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section.

[1793] ACEG Initial Comments at 5; ACEG Reply Comments at 3-5; BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 5, 21; Kansas Corporation Commission Initial Comments at 8-9; NARUC Initial Comments at 23; US DOE Initial Comments at 39-42.

Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages.

806. To account for extreme weather events as part of Benefit 6, transmission providers may incorporate information from the sensitivity they must develop and apply to each Long-Term Scenario that includes multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1794] We reiterate that we require transmission providers to measure the required benefits under each Long-Term Scenario. However, in the case of Benefit 6, transmission providers may measure the benefit of mitigating extreme weather events using the required extreme weather event sensitivity applied to each Long-Term Scenario; we do not require them to separately measure the benefit of mitigating extreme weather events in each scenario without applying that sensitivity.[1795]

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[1794] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section (stating transmission providers must develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area). Transmission providers may also incorporate analyses from an Extreme Weather Vulnerability Assessment as generally described in Order No. 897.

[1795] We recognize that transmission providers may not use an extreme weather event sensitivity that includes system conditions that allow transmission providers to measure the benefit of mitigating unexpected system conditions in every Long-Term Scenario. In such cases, transmission providers must measure the benefit of mitigating unexpected system conditions in each Long-Term Scenario even without an extreme weather event sensitivity applied to those scenarios or must apply a separate sensitivity

807. Consistent with all other benefits that we require transmission providers to measure, we do not require a standardized method for measuring Benefit 6 subject to measuring the components described above.[1796] As the Commission stated in the NOPR, there are different approaches to calculating components of this benefit,[1797] and this final rule provides transmission providers with flexibility in developing the method that they will use to measure this benefit.

808. We disagree with commenters who express general concerns regarding the difficulty of measuring this benefit.[1798] In the NOPR, the Commission identified studies that measured benefits of a transmission facility in a manner similar to the requirements in Benefit 6.[1799] Because we allow flexibility as far as the method transmission providers use to measure each benefit included in the required set of benefits, including Benefit 6, we believe that transmission providers should be able to tailor a method for measuring Benefit 6 that fits their circumstances. Further, transmission providers can build on

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that allows for the measurement of Benefit 6 to each Long-Term Scenario.

[1796] *E.g.*, ACEG Initial Comments at 42-44; DC and MD Offices of People's Counsel Initial Comments at 26-27.

[1797] NOPR, 179 FERC ¶ 61,028 at P 207 (providing examples of CAISO's analysis of Devers-Palo Verde Line No. 2, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line, and a Grid Strategies study).

[1798] NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1799] NOPR, 179 FERC ¶ 61,028 at PP 207, 209.

methods that they use to measure the other benefits required by this final rule to measure Benefit 6. For example, transmission providers can use the same method to measure reduced production costs in accordance with Benefit 6 as they do to measure Benefit 3, Production Costs Savings, but modify the model inputs to capture reduced production costs during extreme weather events and unexpected system conditions. Moreover, we recognize that there is a balance between requiring transmission providers to measure the benefits of Long-Term Regional Transmission Facilities that are most readily measured and ensuring that transmission providers are appropriately capturing the value of Long-Term Regional Transmission Facilities when evaluating them for selection. Even to the extent to which Benefit 6 may be more difficult to measure than the other benefits that we require, we nonetheless find that requiring transmission providers to measure Benefit 6 is necessary because Benefit 6 is significant.[1800]

809. We are unpersuaded by general arguments that transmission providers should not consider this benefit because it varies by transmission planning region or it only accrues to certain entities.[1801] We are not requiring transmission providers to model a specific extreme weather event or unexpected system condition; transmission providers may decide what extreme weather event and unexpected system conditions to model, allowing them to ensure that the conditions modeled are relevant to circumstances in their

[1800] *Supra* P 797.

[1801] Louisiana Commission Initial Comments at 18-19; Pacific Northwest Utilities Initial Comments at 9.

transmission planning region. In response to NRECA's argument that this benefit requires subjective judgement,[1802] we conclude that transmission providers have sufficient expertise to identify and model extreme weather events and unexpected system conditions when evaluating Long-Term Regional Transmission Facilities.[1803] In response to AEP's argument that NOPR Benefit 7 (mitigation of weather and load uncertainty) is of lesser importance compared to other benefits described in the NOPR and should be optional for transmission providers to measure and use,[1804] we disagree because the evidence in the record demonstrates that Final Rule Benefit 6 (which includes NOPR Benefit 7) is significant.[1805]

810. NARUC states that the benefit of mitigation of extreme weather events may need to be more fully considered only in large transmission planning regions or in interregional transmission planning.[1806] Although transmission providers could also consider the benefits of mitigation of extreme weather events as part of interregional transmission coordination, we believe transmission providers can measure and use the benefit of mitigation of extreme weather events in regional transmission planning

[1802] NRECA Initial Comments at 45.

[1803] NESCOE Initial Comments at 42.

[1804] AEP Initial Comments at 27.

[1805] *Supra* note 1769; *see also* ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[1806] NARUC Initial Comments at 21, 23.

processes regardless of the size of the transmission planning region, because extreme weather events can occur and affect the transmission system in any region. If the size of the extreme weather event is larger than the transmission planning region, transmission providers can consider the extent to which they can rely on interregional flows from other transmission planning regions during the extreme weather event. We note that transmission providers in each transmission planning region must coordinate and share information with the transmission providers in each neighboring transmission planning region and must identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs, as described in more detail in the Interregional Transmission Coordination section of this final rule. Better measurement of the benefits of mitigation of extreme weather events as part of regional transmission planning can only help facilitate such efforts. We encourage transmission providers in neighboring transmission planning regions to share information with one another that would be useful to measure Benefit 6 more accurately through their interregional transmission coordination procedures.

811. Some commenters state that the benefits of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty overlap, or should be combined.[1807] We note that Benefit 6, as described above, modifies and combines the benefits proposed in the NOPR of (1) mitigation of extreme events and system

[1807] MISO Initial Comments at 51; PJM Initial Comments at 94.

contingencies and (2) mitigation of weather and load uncertainty, which should address concerns of separately requiring transmission providers to use two similar benefits that some argue could overlap.

### vii. Final Rule Benefit 7: Capacity Cost Benefits from Reduced Peak Energy Losses

#### (a) NOPR Description

812. The Commission described this benefit, NOPR Benefit 8 (renumbered in this final rule as Final Rule Benefit 7), in the NOPR as reduced generation capacity investment needed to meet peak load.[1808] The Commission noted that capacity cost savings from reduced peak energy losses benefits refer to the ability of proposed transmission facilities to lessen the amount of transmission system energy losses during peak-load conditions which, over time, would decrease the need for new generation capacity installations or purchases. To the extent that new transmission facilities result in changes to generation dispatch and flows, transmission system energy losses will also change. If transmission system losses are reduced via the new transmission facilities, transmission providers will not have to construct or procure additional generation to satisfy installed capacity requirements for peak-load conditions. If there is a reduction in energy losses during peak conditions, this would result in, presumably, lowered investments for generation capacity resources to meet the peak load. For example, Entergy found that potential transmission facilities in its footprint could reduce peak-load transmission losses and

[1808] NOPR, 179 FERC ¶ 61,028 at P 210.

associated needed generation investment by 2% of total transmission facility costs.[1809] The Commission noted that capacity cost savings from reduced peak energy losses only attempt to evaluate benefits for peak-load conditions.

813. The Commission stated that one potential way to calculate capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements.[1810] To arrive at the value of associated capital cost savings, the estimated net cost of new entry (Net CONE) (i.e., the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) would be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions that would be passed on to consumers via lowered generation capacity costs.[1811]

**(b) Comments**

814. A number of commenters support mandating consideration of NOPR Benefit 8.[1812] ACEG and DC and MD People's Counsel state that NOPR Benefit 8 is a distinct benefit

[1809] *Id.* P 211 & n.346 (citing ITC, Joint Application, Docket No. EC12-145-000, Ex. ITC-600 (Testimony of Pfeifenberger), at 77-78 (filed Sept. 24, 2012)).

[1810] *Id.* P 212.

[1811] *Id.*

[1812] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32, 45; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy

category that has been measured before.[1813] PIOs state that SPP quantified NOPR Benefit 8 in its 2016 Regional Cost Allocation Review and that "leav[ing] these cost savings on the cutting room floor will ultimately raise costs for consumers and result in an inefficient transmission plan."[1814]

815. Other commenters, such as NARUC, oppose mandating consideration of NOPR Benefit 8. NARUC contends that this benefit is a subset of the lowered system reserve margins benefit. NARUC states that NOPR Benefit 8 is unlikely to occur within organized, competitive generation markets because additional transmission will not deter the installation of new generation under current federal open access policies. However, NARUC argues, this benefit may be attainable in transmission planning regions served by vertically integrated utilities where transmission can substitute for new generation construction. NARUC asserts that hundreds of thousands of megawatts of generation

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Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

[1813] ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12-145-000, Ex. ITC-600 (Testimony of Pfeifenberger), at 77-78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

[1814] PIOs Initial Comments at 42.

currently await interconnection studies in the various RTOs/ISOs and non-RTO/ISO transmission planning regions, and it is difficult to see how construction of new transmission facilities can remove any of this demand for additional generator interconnection.[1815]

816. West Virginia Commission also opposes a requirement to use NOPR Benefit 8, arguing that the calculation requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.[1816]

### (c) Commission Determination

817. As an initial matter, we renumber NOPR Benefit 8 and refer to it in this determination section as Final Rule Benefit 7. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Rule Benefit 7, Capacity Cost Benefits from Reduced Peak Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Final Rule Benefit 7 as reduced generation capacity investment needed to meet peak load.[1817] We find that requiring the use and measurement of Final Rule Benefit 7, as described, is necessary to ensure that capacity cost benefits from reduced peak energy losses are not excluded from Long-Term Regional Transmission Planning

[1815] NARUC Initial Comments at 24.

[1816] West Virginia Commission Supplemental Comments at 4.

[1817] We note that in the NOPR, this benefit was designated as Benefit 8. We have revised the ordering designation of this benefit in this final rule.

because standard production cost modeling and the other benefits that this final rule requires transmission providers to measure and use will not capture this benefit. Absent a requirement for transmission providers to measure and use Final Rule Benefit 7 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

818. One potential way to measure capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements. To arrive at the value of capital cost savings, the estimated net cost of new entry (i.e., the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) could be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions, savings that would be passed on to customers via lowered generation capacity costs.

819. We disagree with NARUC's contention that this benefit is a subset of the lowered system reserve margins benefit and that it is unlikely to occur within organized, competitive generation markets.[1818] ACEG and DC and MD People's Counsel both indicate that Final Rule Benefit 7 is a distinct benefit category that has been measured

[1818] NARUC Initial Comments at 24.

before, citing MISO's Multi-Value Project portfolio, among other examples of its use, which measures capacity cost savings from reduced peak energy losses as an independent benefit.[1819] While we acknowledge that this benefit may have the effect of lowering system reserve margins, we agree with PIOs that these cost savings are distinct from Benefit 2 and that failing to specifically evaluate potential cost savings related to reduced peak energy losses may result in higher capacity costs and relatively inefficient or less cost-effective transmission development. As discussed above, Benefit 2 recognizes potential cost savings of providing additional pathways for connecting generation resources with load. Here, we are assessing the benefits of limiting transmission losses along those pathways. We also note that this approach is consistent with Benefits 3 and 4 above that separately recognize potential cost savings associated with lower production costs and reduced transmission energy losses in energy markets. In light of the evidence that multiple transmission providers have successfully measured this benefit, as well as the example that we provide above describing how a transmission provider may be able to calculate this benefit, we further disagree with West Virginia Commission's argument that calculation of this benefit is based on assumptions that are difficult to quantify in advance.

[1819] ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12-145-000, Ex. ITC-600 (Testimony of Pfeifenberger), at 77-78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

### viii. Other Benefits

#### (a) Comments

820. Numerous commenters address in various ways the other five benefits that the Commission described in the NOPR but that we do not require transmission providers to measure and use in Long-Term Regional Transmission Planning in this final rule: mitigation of weather and load uncertainty,[1820] deferred generation capacity investments, access to lower cost generation, increased competition, and increased market liquidity.[1821] Other commenters address in various ways benefits not listed in the NOPR for transmission providers to consider for use in evaluating Long-Term Regional Transmission Facilities.[1822]

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[1820] We note that elements of this benefit are now contained in Benefit 6, the description of which has been revised from the NOPR.

[1821] Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32, 45-48; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25-27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20, 28-30; ENGIE Reply Comments at 2-3; Hannon Armstrong Initial Comments at 2-3; Idaho Power Initial Comments at 7-8; Interwest Initial Comments at 12-14; ISO-NE Initial Comments at 34; Joint Consumer Advocates Initial Comments at 11-12; MISO Initial Comments at 50-51; NARUC Initial Comments at 21, 24-25; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11-14; North Carolina Commission and Staff Initial Comments at 6-7; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; PJM Initial Comments at 94; PJM Market Monitor Initial Comments at 5-6; PPL Initial Comments at 13-15; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27-28; Southern Initial Comments at 25-27; West Virginia Commission Supplemental Comments at 4; US DOE Initial Comments at 31-32.

[1822] ACEG Initial Comments at 6-8; AEE Reply Comments at 25-26; AEP Initial

**(b) Commission Determination**

821. We decline to require transmission providers to measure and use the remaining five benefits described in the NOPR in Long-Term Regional Transmission Planning (i.e., mitigation of weather and load uncertainty, generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity). We find that the required set of benefits that we adopt herein is a sufficiently broad range of benefits to ensure that transmission providers are identifying, evaluating, and selecting Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. As such, we find that the measurement and use of additional benefits in Long-Term Regional Transmission Planning is not necessary to ensure that rates remain just and reasonable.

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Comments at 6, 23-27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-23; California Commission Initial Comments at 31-34; California Energy Commission Initial Comments at 3; CARE Coalition Initial Comments at 32-33; Certain TDUs Reply Comments at 1-3; Clean Energy Associations Initial Comments at 19-20; Clean Energy Buyers Initial Comments at 20-21; Clean Energy States Initial Comments at 6-8; DC and MD Offices of People's Counsel Initial Comments at 18-19; Entergy Initial Comments at 21; Environmental Groups Supplemental Comments at 2-3; Grand Rapids NAACP Initial Comments at 21-23; GridLab Initial Comments at 25-28; Interwest Initial Comments at 13-14; ITC Initial Comments at 21-22; Joint Consumer Advocates Initial Comments at 11-12; Large Public Power Initial Comments at 28-29; Michigan Commission Initial Comments at 7; Nevada Commission Initial Comments at 10-11; Northwest and Intermountain Initial Comments at 15-16; NYISO Initial Comments at 39; Pattern Energy Reply Comments at 8-9; PIOs Initial Comments at 43-44; PIOs Reply Comments at 7-8; PJM Initial Comments at 94-96; Policy Integrity Initial Comments at 28; Policy Integrity Supplemental Comments at 4-8; PPL Initial Comments at 14-15; R Street Initial Comments at 9-10; Rail Electrification Initial Comments at 6-7; RMI Initial Comments at 2; SEIA Initial Comments at 16-17; Shell Initial Comments at 14-16; Tabors Caramanis Rudkevich Initial Comments at 6; US DOE Initial Comments at 33-34; Vistra Initial Comments at 15-16; WE ACT Initial Comments at 2-3.

822. However, we recognize that Long-Term Regional Transmission Facilities may provide additional benefits that may merit consideration when transmission providers are identifying, evaluating, and selecting such facilities to address Long-Term Transmission Needs more efficiently or cost-effectively. Therefore, transmission providers may measure and use additional benefits beyond those included in the required set of benefits in Long-Term Regional Transmission Planning, including on a transmission facility or plan-specific basis, subject to the requirement that they do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.

### 3. Identification, Measurement, and Evaluation of the Benefits of Long-Term Regional Transmission Facilities

#### a. NOPR Proposal

823. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits that they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers would be required to explain the rationale for using the benefits identified.[1823]

[1823] NOPR, 179 FERC ¶ 61,028 at P 183.

**b. Comments**

824. Many commenters support requiring identification of, and transparency regarding, the benefits that transmission providers will use in Long-Term Regional Transmission Planning.[1824] For example, Nebraska Commission states that the NOPR proposal will foster the necessary flexibility to accommodate varying needs and approaches of different transmission planning regions.[1825]

825. Certain TDUs and Michigan Commission state that transmission providers must clearly articulate their methods for calculating identified benefits.[1826] Certain TDUs further state that benefits should be evaluated with consistent reference cases to ensure consistency across scenarios.[1827] Certain TDUs and Entergy state that transmission providers should incorporate their benefit calculation methods, as well as, according to Entergy, their role in selection, into the OATT.[1828] Entergy argues that the Commission

[1824] APPA Initial Comments at 5; Avangrid Initial Comments at 7, 29; Business Council for Sustainable Energy Initial Comments at 5; California Commission Initial Comments at 28-30; California Energy Commission Initial Comments at 3; ENGIE Reply Comments at 3; Handy Law Initial Comments at 8; Massachusetts Attorney General Initial Comments at 3; Michigan Commission Initial Comments at 6; Nebraska Commission Initial Comments at 7; NESCOE Initial Comments at 44 (citing NOPR, 179 FERC ¶ 61,028 at PP 183, 186); NRECA Initial Comments at 46; NYISO Initial Comments at 37-38; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 7; Vermont State Entities Initial Comments at 6.

[1825] Nebraska Commission Initial Comments at 7.

[1826] Certain TDUs Initial Comments at 13; Michigan Commission Initial Comments at 6.

[1827] Certain TDUs Initial Comments at 13-14.

[1828] Certain TDUs Initial Comments at 14-15; Entergy Reply Comments at 4-5

should allow transmission providers to use different benefits on a regional or subregional level, but that benefits should not change from one transmission project or portfolio to the next without an OATT amendment.[1829]

826. MISO TOs state that MISO already meets the NOPR's proposed requirement to identify benefits used in Long-Term Regional Transmission Planning and explain how they will be calculated.[1830]

827. Some commenters express concerns with the Commission's proposed benefit identification requirement,[1831] including concerns over perceived excessive quantification[1832] or requirements to calculate benefits individually.[1833] Duke asserts that the Commission should clarify that it will not force transmission providers to assign

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(citing *City & Cnty. of San Francisco v. FERC*, 24 F.4th 652, 661 (D.C. Cir. 2022); *Sw. Power Pool, Inc.*, 180 FERC ¶ 61,074, at PP 24-31 (2022), *order on reh'g and setting aside*, 182 FERC ¶ 61,100 (2023)).

[1829] Entergy Reply Comments at 5.

[1830] MISO TOs Initial Comments at 19-22 (citing MISO, Electric Tariff, attach. FF §§ II.C.2, II.C.5; MISO, *LRTP Tranche 1 Portfolio Detailed Business Case*, at 15-49, 60 (June 25, 2022), https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf).

[1831] DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13-14; Louisiana Commission Initial Comments at 18; Michigan Commission Initial Comments at 6; US Chamber of Commerce Initial Comments at 7-8. Further detail on the basis for these commenters' concerns is provided *infra*.

[1832] *See, e.g.*, Duke Initial Comments at 24.

[1833] *See, e.g.*, EEI Initial Comments at 20.

dollar values for every benefit because some benefits' quantification is subjective.[1834] EEI asserts that transmission providers should not have to calculate all of the benefits for a transmission project but states that those benefits used for cost allocation purposes should be quantifiable.[1835] NYISO requests that the final rule confirm that it does not prescribe how benefits must be calculated and, more specifically, that transmission providers are not required to calculate the listed benefits in the exact manner described in the NOPR.[1836]

828. MISO notes that the benefits it currently uses in regional transmission planning are not all specified in the Tariff itself but were developed as part of the review process with MISO stakeholders. MISO adds that the flexibility to look for relevant benefits and apply them in long-term planning scenarios is important in the process to identify long-term regional solutions that reflect the needs and value-drivers of the MISO footprint.[1837] MISO states that if limited to a prescriptive set of benefits, MISO may not be in the same position to move forward the transmission projects of the greatest benefit and value to MISO and its stakeholders.[1838]

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[1834] Duke Initial Comments at 24.

[1835] EEI Initial Comments at 20.

[1836] NYISO Initial Comments at 36-40.

[1837] MISO Initial Comments at 9-10.

[1838] *Id.* at 9.

829. Some commenters opine on requirements or best practices for identifying, measuring, and combining benefits.[1839] For example, some commenters comment on the measurement and/or calculation of benefits.[1840] Entergy argues that the Commission should require all benefits to be reasonably achievable in real-time operations.[1841] SPP Market Monitor states that assumptions into benefit calculations should be improved to ensure that they result in just and reasonable rates.[1842] Large Public Power emphasizes that the Commission should clarify that benefits must reflect load-serving entities' actual use of proposed transmission facilities, measured by anticipated power flows.[1843]

[1839] Acadia Center and CLF Initial Comments at 23; ACORE Reply Comments at 3; ACEG Initial Comments at 32; AEP Initial Comments at 21-24; APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 11; Clean Energy Associations Initial Comments at 20-21; DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13-14; Large Public Power Initial Comments at 28; Louisiana Commission Initial Comments at 18; Michigan State Entities Initial Comments at 5-7; NARUC Initial Comments at 20-26; NASUCA Initial Comments at 10; NRECA Initial Comments at 45; NYISO Initial Comments at 37; PJM Market Monitor Initial Comments at 4; SEIA Initial Comments at 18-19; Six Cities Initial Comments at 2-3; Southern Initial Comments at 31; SPP Market Monitor Initial Comments at 11; US Chamber of Commerce Initial Comments at 7-8; US DOE Initial Comments at 31; Vermont State Entities Initial Comments at 6.

[1840] AEP Initial Comments at 21-24; Clean Energy Associations Initial Comments at 21; Large Public Power Initial Comments at 28; SEIA Initial Comments at 18-19; SPP Market Monitor Initial Comments at 11.

[1841] Entergy Initial Comments at 22.

[1842] SPP Market Monitor Initial Comments at 11.

[1843] Large Public Power Initial Comments at 28.

830. SEIA suggests that there are many resources to inform methods for the calculation of benefits, including MISO's Long Range Transmission Plan Tranche 1 portfolio.[1844] Also referencing MISO's process, AEP contends that the benefits of regional transmission facilities should be evaluated collectively, through a multi-value analysis, and cites MISO's existing process as an example.[1845]

831. Some commenters opine on the need for quantification and/or specificity of benefits.[1846] DC and MD Offices of People's Counsel assert that any benefit used should be pre-defined and its measurement accurate and transparent.[1847] PIOs also state that the Brattle-Grid Strategies Oct. 2021 Report provides evidence that benefits from transmission facilities are not difficult to quantify despite claims to the contrary.[1848] NASUCA asserts that the methods for calculating and assigning benefits should be based on objective, measurable, clear, and specific metrics.[1849] Similarly, Illinois Commission,

[1844] SEIA Initial Comments at 18-19 (citing Rob Gramlich, *Enabling Low-Cost Clean Energy & Reliable Service Through Better Transmission Benefits Analysis*, at 17, https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf).

[1845] AEP Initial Comments at 21-24.

[1846] ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31); Concerned Scientists Reply Comments at 8-10; DC and MD Offices of People's Counsel Initial Comments at 19; Entergy Initial Comments at 22; NASUCA Initial Comments at 10; US DOE Initial Comments at 31.

[1847] DC and MD Offices of People's Counsel Initial Comments at 19.

[1848] PIOs Initial Comments at 42-44.

[1849] NASUCA Initial Comments at 10.

Pacific Northwest Utilities, and NARUC assert that transmission benefits must be verifiable and quantifiable.[1850]

832. A few commenters address the ease of quantification of the benefits listed in the NOPR. NARUC states that NOPR Benefits 1-5 and 8-10 seem somewhat capable of quantification.[1851] NRECA asserts that the benefits at the top of the list in the NOPR are reasonably quantifiable, while those farther down the list require more subjective judgements.[1852] APPA agrees that some of the benefits listed in the NOPR would be more challenging to quantify and therefore would be more difficult to justify as a just and reasonable way to allocate costs.[1853]

833. Some commenters support the use of benefit-cost analysis frameworks.[1854] Michigan State Entities express that having a prescribed benefit-cost analysis framework can help ensure appropriate quantification of benefits, adding that there is less transparency when individual transmission providers may determine how these benefits stack up against each other.[1855] Therefore, Michigan State Entities recommend that the

[1850] Illinois Commission Initial Comments at 13-14; NARUC Initial Comments at 20-25; Pacific Northwest Utilities Initial Comments at 8-9.

[1851] NARUC Initial Comments at 21.

[1852] NRECA Initial Comments at 45.

[1853] APPA Initial Comments at 32.

[1854] Michigan State Entities Initial Comments at 5-7; Six Cities Initial Comments at 2-3; Southern Initial Comments at 31; Vermont State Entities Initial Comments at 6-7.

[1855] Michigan State Entities Initial Comments at 5.

Commission adopt the cost-benefit analysis framework already used throughout the federal government. According to Michigan State Entities, the Commission's legal authority to do so is well-established by court decisions and it would help to ensure sufficient regional transmission cooperation to achieve just and reasonable rates.[1856]

834. Six Cities argues that transmission planning should assess both project benefits and costs.[1857] Vermont State Entities agree that a comprehensive benefit-cost analysis would lead to better and more cost-effective transmission planning.[1858] Southern also states that the burdens associated with proposed transmission projects should be recognized, including not only immediate cost and rate impacts, but also effects on local communities and landowners and issues of equity and environmental justice.[1859]

835. Likewise, certain commenters state that they support the adoption of benefit-cost analysis using quantifiable, replicable, non-duplicative, and forward-looking metrics.[1860] US Chamber of Commerce contends that the objective nature of such metrics should limit uncertainty otherwise present in projections spanning multiple decades and reduce

[1856] *Id.* at 6-7.

[1857] Six Cities Initial Comments at 2-3.

[1858] Vermont State Entities Initial Comments at 6-7.

[1859] Southern Initial Comments at 31.

[1860] City of New Orleans Council Initial Comments at 11; Entergy Initial Comments at 22; Louisiana Commission Initial Comments at 18; US Chamber of Commerce Initial Comments at 7-8.

the variability and error in benefit calculations.[1861] Acadia Center and CLF and ACEG argue that an unbiased analysis of both benefits and costs is essential for ensuring just and reasonable rates and that the Commission should seek to ensure that a minimum set of benefits is applied consistently across RTO/ISO and non-RTO/ISO transmission planning regions.[1862] ACORE agrees with US DOE that consistency in benefit quantification could facilitate improved interregional transmission planning.[1863]

836. Other commenters state that the NOPR's proposed reforms will help improve transmission providers' existing benefit-cost analyses.[1864] GridLab states that the NOPR's approach balances regional flexibility with federal standardization in benefit categories across transmission providers and more accountability by transmission providers in their benefit-cost analysis.[1865] PJM Market Monitor states that PJM's current benefit-cost analysis does not accurately measure the costs and benefits of transmission projects because it does not account for the fact that benefits are uncertain and sensitive to modeling assumptions or that costs may exceed estimates.[1866] Illinois Commission

[1861] US Chamber of Commerce Initial Comments at 8.

[1862] Acadia Center and CLF Initial Comments at 23; ACEG Initial Comments at 32.

[1863] ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31).

[1864] GridLab Initial Comments at 25; PJM Market Monitor Initial Comments at 4-5; Southeast PIOs Initial Comments at 49-50.

[1865] GridLab Initial Comments at 25.

[1866] PJM Market Monitor Initial Comments at 4-5.

states that the use of too many metrics could lead to the evaluation of transmission projects based on the margins and inequitable cost allocation.[1867] Illinois Commission further states that some metrics may be most relevant for interregional and regional transmission projects identified in the Long-Term Regional Transmission Planning process and that the Commission can aid transmission planning regions in putting together a shorter list of these metrics.[1868]

### c. Commission Determination

837. We adopt the NOPR proposal, with modification, and require transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the seven benefits included in the required set of benefits that we require them to measure and use in Long-Term Regional Transmission Planning. As discussed above, we clarify that transmission providers may use and measure additional benefits, beyond the seven required by this final rule. [1869]

838. We find that requiring such a description in transmission providers' OATTs for the seven required benefits is necessary to ensure that all stakeholders have transparency

[1867] Illinois Commission Initial Comments at 13.

[1868] *Id.* at 14.

[1869] While we conclude that it is important for transmission providers to at minimum use and measure the required seven benefits, we agree with MISO that the flexibility to look for relevant benefits and apply them in long-term planning scenarios can be important in the process to identify long-term regional solutions that reflect region-specific needs and value-drivers. MISO Initial Comments at 9. We therefore afford flexibility to transmission planners in identifying and measuring benefits that go beyond the core set of seven required here.

regarding the benefits that transmission providers use to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. We further conclude that requiring inclusion of this information in the OATT will better ensure transmission providers measure and use the set of benefits required in the final rule in Long-Term Regional Transmission Planning.

839. Some commenters express concerns regarding excessive quantification of benefits.[1870] But the approach adopted in this final rule—of requiring transmission providers to measure and use a required set of benefits in Long-Term Regional Transmission Planning and requiring transmission providers to include in their OATTs a general description of the method they will use to measure each of those benefits—represents a reasonable balance between specificity and flexibility. As discussed above, we provide flexibility to transmission providers to specify the method for measuring each of the seven required benefits. However, because our requirement that transmission providers measure and use these benefits in Long-Term Regional Transmission Planning is necessary to address the identified deficiencies in existing regional transmission planning and cost allocation processes, we find that it is also necessary for transmission providers to include in their OATTs a general description of how they will measure each of these benefits. Such a requirement will ensure that transmission providers consider a sufficiently broad range of benefits when determining whether to select a Long-Term

[1870] *See, e.g.*, Duke Initial Comments at 24.

Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs.

840. In response to some commenters, such as MISO, that urge that requiring details on measurement of benefits to be incorporated into the OATT could impede development and use of new transmission metrics, we clarify that the description for each required benefit in the OATT must only be sufficient to enable stakeholders to understand the manner by which transmission providers will measure these benefits. We do not require further details on measurement of the benefits to be included in the OATT.

841. Large Public Power asks that the Commission clarify that any acceptable list of benefits detailed in compliance filings must emphasize load-serving entities' actual use of the proposed transmission facilities, which should be measured by anticipated power flows that occur across these facilities.[1871] We decline to adopt Large Public Power's suggested clarification as we are not mandating any particular method for measuring the seven benefits included in the required set of benefits.

842. We decline certain commenters' requests to require that transmission providers justify why they omit any categories of benefits.[1872] Such a requirement is unnecessary because of our modifications to the NOPR proposal, which now require transmission

[1871] Large Public Power Initial Comments at 28.

[1872] GridLab Initial Comments at 25; NYISO Initial Comments at 37-38; Vermont State Entities Initial Comments at 6-7.

providers to measure and use the required set of benefits in Long-Term Regional Transmission Planning.

### 4. Evaluation of Transmission Benefits Over a Longer Time Horizon

#### a. NOPR Proposal

843. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the regional transmission facilities.[1873]

844. The Commission proposed to require transmission providers to evaluate benefits over this time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such regional transmission facilities in a manner that is at least roughly commensurate with estimated benefits. The Commission proposed that for consistency and a matching comparison of benefits and costs over time, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, that transmission providers

[1873] NOPR, 179 FERC ¶ 61,028 at P 227.

should estimate those future costs over the same time horizon as the estimated benefit.[1874] The Commission proposed that approaches may exceed this minimum requirement, but transmission providers must demonstrate that their proposal is consistent with or superior to any final rule in this proceeding.

**b. Comments**

**i. Requirement for a Benefits Evaluation Time Horizon of a Minimum of 20 Years from the In-Service Date**

845. Several commenters support the Commission's proposal to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.[1875] NARUC, for example, states that transmission planning must strike a reasonable balance between considering benefits only through the end of the transmission planning horizon regardless of the transmission facility's in-service date and considering benefits over its full expected life, which NARUC states that the NOPR proposal achieves.[1876] Northwest and Intermountain state that they cautiously support the Commission's proposal to establish a minimum 20-year

[1874] *Id.* P 228.

[1875] ACEG Initial Comments at 24; California Commission Initial Comments at 36; Certain TDUs Reply Comments at 3; ITC Initial Comments at 22-23; NARUC Initial Comments at 26-27; NYISO Initial Comments at 40; OMS Initial Comments at 8-9; Pacific Northwest State Agencies Initial Comments at 16-19.

[1876] NARUC Initial Comments at 26.

horizon for the calculation of benefits, noting that their concerns are mitigated by the NOPR proposal to allow flexibility within each transmission planning region to tailor cost allocation criteria to that region's needs.[1877] Similarly, Vermont State Entities and NESCOE state that a rigid one-size-fits-all rule could be counterproductive and would not necessarily lead to just and reasonable transmission rates.[1878] NARUC states that, while it supports the NOPR proposal, transmission providers should be allowed independent entity variations to deviate above or below the 20-year horizon after gaining experience with Long-Term Regional Transmission Planning.[1879] NYISO contends that it already employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.[1880]

846. MISO supports the Commission's proposal, stating that a minimum period of 20 years is adequate to assess the benefits of regional transmission facilities.[1881] MISO cautions, however, that the benefits determined over this time horizon represent the minimum benefits that a regional transmission facility provides and that the analysis should recognize that additional benefits would be realized over the life of the investment

[1877] Northwest and Intermountain Initial Comments at 8.

[1878] NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 6.

[1879] NARUC Initial Comments at 39-40.

[1880] NYISO Initial Comments at 40.

[1881] MISO Initial Comments at 52.

even if changing system conditions create uncertainty as to the precise value of those benefits.[1882]

847. Other commenters suggest that the time horizon for the evaluation of benefits in Long-Term Regional Transmission Planning should align with the useful life of the transmission asset.[1883] Breakthrough Energy and CARE Coalition contend that the proper time horizon for evaluation of benefits in standard economics and public policy is the life of the transmission asset, noting that transmission assets can often last 40 years or longer.[1884] ACEG agrees, noting that, while it supports use of a 20-year minimum horizon to evaluate benefits, standard regulatory practice for a benefit-cost analysis is typically the life of the asset.[1885] Likewise, PIOs contend that, while they agree with the NOPR proposal, it would be preferable to align the time horizon for evaluating benefits with the useful life of the transmission project.[1886] PIOs state that calculating the benefits and costs of a transmission project over a shorter timespan can understate the benefit-cost

[1882] *Id.*

[1883] ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40-41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16-17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 17-18; Interwest Initial Comments at 14; Interwest Reply Comments at 6-7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40-41; US DOE Initial Comments at 33-34; WIRES Initial Comments at 7.

[1884] Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40-41.

[1885] ACEG Initial Comments at 24.

[1886] PIOs Initial Comments at 40 (citing PIOs Initial Comments Ex. A, ¶¶ 24-29).

ratio because benefits tend to grow over time, while transmission revenue requirements will decline over time as the asset is depreciated.[1887]

848. CTC Global states that while it supports the NOPR proposal, it argues that it would be more appropriate to align the timeline for evaluating benefits with the asset life, because while advanced conductors are almost always more expensive than legacy conductors initially, their costs are offset by efficiency and resilience benefits decades into the future.[1888] Indicated PJM TOs state that benefits "should be calculated on the same time horizon as the project that is being assessed to allow for the ability to properly compare projects."[1889]

849. Given that transmission assets often have a useful life of at least 40 years, US DOE encourages the Commission to require transmission providers to evaluate costs and benefits over a minimum of 30 years after the in-service date of a transmission facility rather than the proposed 20 years. According to US DOE, doing so would better align with the useful life assumptions that generation developers make.[1890]

850. Clean Energy Buyers and PG&E suggest that benefits should be evaluated over the same 20-year horizon as the proposed Long-Term Regional Transmission Planning transmission planning horizon.[1891] Similarly, PPL states that, while it supports the

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[1887] *Id.* (citing PIOs Initial Comments Ex. A, ¶ 28).

[1888] CTC Global Initial Comments at 16-17.

[1889] Indicated PJM TOs Initial Comments at 18.

[1890] US DOE Initial Comments at 33-34.

[1891] Clean Energy Buyers Initial Comments at 20; PG&E Initial Comments at 7.

proposed 20-year minimum duration to evaluate benefits in Long-Term Regional Transmission Planning, the Commission should require transmission providers to measure benefits from the study date rather than the proposed in-service date of the Long-Term Regional Transmission Facility. PPL contends that the NOPR proposal would introduce significant variability that will make it challenging to align the outcome with the long-term need and would incentivize transmission developers to delay or adjust the timing of transmission projects to maximize the demonstrated benefit.[1892]

851. In contrast, GridLab contends that the 20-year Long-Term Regional Transmission Planning transmission planning horizon need not correspond with the time horizon over which transmission providers evaluate the benefits and costs of potential transmission investments. GridLab recommends that the Commission clarify the distinction between the requirement for a 20-year transmission planning horizon and for a 20-year period to evaluate benefits, while keeping both requirements.[1893]

852. Many commenters assert that evaluating benefits over a 20-year time horizon is difficult or speculative.[1894] Ohio Consumers and Dominion argue that, since transmission providers would be required to plan for potential transmission needs in 20 years and evaluate benefits over a 20-year project life span, the requirement effectively amounts to

[1892] PPL Initial Comments at 15-17.

[1893] GridLab Initial Comments at 6-8.

[1894] APPA Initial Comments at 32; Dominion Initial Comments at 17; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; PJM Initial Comments at 97.

a 40-year cost allocation process and will be particularly challenging.[1895] APS agrees, stating that calculating benefits over a potential 40 years may lead to benefit calculations that are overstated or yield unreasonable or unrealistic results.[1896]

853. Some commenters request certain clarifications or modifications to address that uncertainty.[1897] For example, Exelon states that benefits should tie back to customer value and suggests that the Commission should give transmission providers flexibility to assign more weight to nearer-term benefits tied to specific savings that are more certain.[1898] SERTP Sponsors and Duke agree, and Duke requests that the Commission clarify that transmission providers are permitted to discount benefits based on increased uncertainty in later years for purposes of evaluating, selecting, and allocating the costs of Long-Term Regional Transmission Facilities.[1899]

854. Several commenters oppose requiring a minimum 20-year horizon for evaluating benefits of Long-Term Regional Transmission Facilities.[1900] For example, Idaho Commission argues that the NOPR proposal is founded on benefits that are not

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[1895] Ohio Consumers Initial Comments at 8.

[1896] APS Initial Comments at 8-9.

[1897] Duke Initial Comments at 23-24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

[1898] Exelon Initial Comments at 16.

[1899] Duke Initial Comments at 23-24; SERTP Sponsors Initial Comments at 31.

[1900] Dominion Reply Comments at 4-5; Idaho Commission Initial Comments at 4; NARUC Initial Comments at 5-6; NESCOE Initial Comments at 44-45; Pacific Northwest Utilities Initial Comments at 6-7; Pennsylvania Commission Initial Comments at 4-5.

"generally accepted or regionally flexible" and may not be beneficial for regional transmission planning benefit evaluation.[1901] Furthermore, Idaho Commission argues, it is difficult to accurately predict and quantify benefits over a 20-year period for purposes of cost allocation.[1902]

855. Similarly, Dominion requests that the Commission decline to adopt the NOPR proposal or provide clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period. Dominion states that it would be unreasonable for the Commission to require transmission providers to consider benefits over a 40-year period, because identifying benefits and beneficiaries that far into the future would involve too much speculation.

856. Pennsylvania Commission requests that the Commission revise the NOPR proposal to set a long-term horizon of no longer than 20 years for planning and benefit-cost analysis. Pennsylvania Commission argues that as the planning and benefit-cost analysis horizons lengthen, uncertainty in predictions of load growth, costs, and benefits will increase, potentially leading to uneconomic transmission projects.[1903] Pacific Northwest Utilities oppose the NOPR proposal because, they argue, beneficiaries and benefits cannot be identified or quantified with any reasonable certainty over a 20-year transmission planning horizon. Specifically, Pacific Northwest Utilities contend that

[1901] Idaho Commission Initial Comments at 4.

[1902] *Id.*

[1903] Pennsylvania Commission Initial Comments at 4-5.

there is no plausible reason to believe that such speculative benefits would be roughly commensurate with the costs that are allocated to identified beneficiaries.[1904]

### ii. Applicability of Benefits Evaluation Horizon to Long-Term Regional Transmission Planning Stages (Evaluation of Facilities, Selection, and Cost Allocation)

857. Pacific Northwest State Agencies supports the Commission's proposal to require that transmission providers evaluate benefits over a consistent time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such transmission facilities in a manner that is roughly commensurate with estimated benefits.[1905]

858. Several commenters also support the Commission's proposal that, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, they should estimate those future costs over the same time horizon as the estimated benefits.[1906] For instance, MISO states that costs and benefits for regional transmission investments should be evaluated using the same time

[1904] Pacific Northwest Utilities Initial Comments at 7 (citing *ICC v. FERC I*, 576 F.3d 470).

[1905] Pacific Northwest State Agencies Initial Comments at 18.

[1906] Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); MISO Initial Comments at 53; NARUC Initial Comments at 27; OMS Initial Comments at 8-9; Pacific Northwest State Agencies Initial Comments at 18.

horizon to ensure there is consistency in accounting for the effects of time in the calculations.[1907] MISO attests that since benefits are only realized once a transmission project or portfolio of projects is in service, transmission providers should assess the benefits over the period of time starting with the in-service date to align with costs.[1908] Pacific Northwest State Agencies and Certain TDUs agree.[1909]

### c. Commission Determination

859. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, and we require that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities.[1910] However, we do not adopt the NOPR proposal to require a minimum 20-year horizon to calculate benefits for purposes of cost allocation.

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[1907] MISO Initial Comments at 53.

[1908] *Id.*

[1909] Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); Pacific Northwest State Agencies Initial Comments at 18.

[1910] In the NOPR, the Commission used the term "regional transmission facilities"; however, as this reform only concerns Long-Term Regional Transmission Planning, we clarify that the Commission's intent was to refer only to Long-Term Regional Transmission Facilities. As discussed in the Development of Long-Term Scenarios section, transmission providers also use these benefits to help to inform their identification of Long-Term Transmission Needs that manifest during the 20-year transmission planning horizon.

As described in the Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities section of this final rule, requiring transmission providers to adopt this provision for purposes of cost allocation would unduly complicate development and review of Long-Term Regional Transmission Cost Allocation Methods, with little incremental gain. Lastly, for consistency and a matching comparison of costs over time, we adopt the NOPR proposal to require that, to the extent that transmission providers estimate the costs of Long-Term Regional Transmission Facilities beyond the in-service date of the transmission facilities, they must estimate those future costs over the same time horizon as the estimated benefits.

860. We find that calculating benefits both for the evaluation and selection of Long-Term Regional Transmission Facilities over a timeline that covers, at a minimum, 20 years starting from the estimated in-service date of the Long-Term Regional Transmission Facility, strikes an appropriate balance. This balance reasonably reflects the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, a time period that can exceed 40 years,[1911] while recognizing the inherent difficulties in attempting to predict system conditions too far into the future. As described in the Long-Term Regional Transmission Planning section of this final rule, the

[1911] ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40-41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16-17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 18; Interwest Initial Comments at 14; Interwest Reply Comments at 7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40-41; US DOE Initial Comments at 33-34; WIRES Initial Comments at 7.

uncertainty associated with forecasting future transmission needs over a long-term transmission planning horizon can be mitigated through the use of multiple Long-Term Scenarios and sensitivities.

861. Specifically, this final rule requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and also requires transmission providers to update their assumptions periodically. Additionally, transmission providers are permitted to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in Factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios.[1912] Because of these reforms, we believe that transmission providers will be able to identify Long-Term Transmission Needs with a higher likelihood of occurrence, and, therefore, the benefits resulting from Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address these Long-Term Transmission Needs will similarly be more certain.

862. Moreover, as described in the Evaluation and Selection of Regional Transmission Facilities section of this final rule, we provide transmission providers with considerable flexibility to develop an evaluation process and selection criteria that will provide them

[1912] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Categories of Factors section.

the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities. In particular, transmission providers have the flexibility to evaluate Long-Term Regional Transmission Facilities and their measured benefits across the different Long-Term Scenarios and sensitivities in a manner that addresses the inherent uncertainty in Long-Term Regional Transmission Planning, for example through the use of a least-regrets or a weighted-benefits approach. Lastly, as is the case under the existing Order No. 1000 regional transmission planning processes, the final rule does not require transmission providers to select any transmission facilities as part of Long-Term Regional Transmission Planning. Taken together, the aspects of the final rule described above offer transmission providers meaningful tools to address uncertainty in Long-Term Regional Transmission Planning, including the calculation of benefits.

863. We disagree with NESCOE and Vermont State Entities, who argue that a requirement to calculate benefits over a minimum of 20 years from the estimated in-service date is overly rigid and may not lead to transmission rates that are just and reasonable. As discussed above, this requirement strikes a reasonable balance between the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, while recognizing the inherent difficulties in attempting to forecast system conditions too far into the future. Further, allowing transmission providers to calculate benefits over a shorter period would more likely undervalue the total benefits that Long-Term Regional Transmission Facilities can provide and could therefore lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional

Transmission Facilities that provide significant net benefits may not be selected to address Long-Term Transmission Needs. Lastly, and as stated above, we are not requiring transmission providers to use a minimum 20-year horizon to calculate benefits for purposes of cost allocation.

864. Similarly, we also disagree with commenters that suggest that the results of the benefits evaluation would not be accurate or dependable enough for transmission providers to use in making the decision to select Long-Term Regional Transmission Facilities.[1913] We further note that transmission providers in multiple transmission planning regions already evaluate the benefits of transmission facilities over a 20-year time horizon as part of their regional transmission planning processes.[1914] For example, NYISO states that it employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.[1915]

[1913] APPA Initial Comments at 32; APS Initial Comments at 8-9; Dominion Initial Comments at 17; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 7; PJM Initial Comments at 97.

[1914] MISO Initial Comments at 52; NYISO Initial Comments at 40; *see also* MISO, *LRTP Business Case*, Long Range Transmission Planning Workshop, at 7 (Jan. 21, 2022, revised Feb. 2, 2022), https://cdn.misoenergy.org/20220121%20LRTP%20Workshop%20Item%2004%20Business%20Case%20Presentation619895.pdf; CAISO, *20-Year Transmission Outlook* (Jan. 31, 2022), http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf; SPP Engineering, *2021 SPP Transmission Expansion Plan Report* (Jan. 11, 2021), https://spp.org/documents/56611/2021%20step%20report.pdf.

[1915] NYISO Initial Comments at 40.

865. Some commenters suggest that the Commission should provide additional flexibility to account for uncertainty in calculating benefits over a minimum 20-year time horizon, including that the Commission make clear that transmission providers may discount or weight the calculated benefits based on the relative certainty throughout the benefits horizon.[1916] As we described above, this final rule affords transmission providers considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning, including by allowing transmission providers to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. Given these flexibilities, we find that while transmission providers may discount the benefits calculated for purposes of determining a present value of those benefits, they may not further discount those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits.

866. In response to Dominion's request for clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period, we reiterate that transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities over a minimum of 20 years from their estimated in-service date, even if the estimated in-service date is 20 years into the future. The failure

[1916] Duke Initial Comments at 23-24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

to take such an approach could result in transmission providers' consideration of a Long-Term Regional Transmission Facility's cost but not the facility's corresponding benefits.

867. We also decline to modify the proposal, as requested by Pennsylvania Commission,[1917] to require a benefits horizon of no longer than 20 years as a means of reducing speculation and uncertainty in calculating benefits of Long-Term Regional Transmission Facilities, as well as NARUC's request that the Commission permit transmission providers to deviate below the 20-year benefit evaluation horizon. As explained above, a minimum of 20 years strikes a reasonable balance for calculating the benefits of Long-Term Regional Transmission Facilities. In addition, as indicated by many commenters, calculating the benefits of a Long-Term Transmission Facility over a time horizon longer than 20 years is consistent with the long life of transmission facilities—which generally exceeds 20 years by a substantial margin—and also consistent with the fact that transmission facilities may provide significant benefits over their entire useful life. While we reiterate that transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, to the extent that transmission providers would like to consider a longer time horizon for the evaluation of benefits, they may propose to do so on compliance.

868. In response to Pacific Northwest Utilities' argument that transmission providers will be unable to identify the beneficiaries of Long-Term Regional Transmission

[1917] Pennsylvania Commission Initial Comments at 4-5.

Facilities over a 20-year time horizon, and therefore that the costs of Long-Term Regional Transmission Facilities will not be allocated in a manner that is roughly commensurate with the benefits received,[1918] we note that this final rule modifies the NOPR proposal and transmission providers are not required to use a benefits time horizon of 20 years for purposes of cost allocation. We find this modification to the final rule moots Pacific Northwest Utilities' argument.

869. We disagree with PPL's comments arguing that calculating benefits from the estimated in-service date of a Long-Term Regional Transmission Facility will present challenges to align the outcome with the actual needs in Long-Term Regional Transmission Planning or otherwise create perverse incentives for transmission developers to delay or adjust the timing of certain transmission projects to maximize benefits.[1919] To the contrary, establishing a minimum benefits horizon of 20 years starting from the estimated in-service date of Long-Term Regional Transmission Facilities will allow for a comparable evaluation of benefits that identified Long-Term Regional Transmission Facilities may provide, even when such facilities may be placed in service at different times during the transmission planning horizon. We therefore decline PPL's request that the Commission modify the proposal to require that transmission providers measure benefits for a minimum of 20 years starting from the

[1918] Pacific Northwest Utilities Initial Comments at 7 (citing *ICC v. FERC I*, 576 F.3d 470).

[1919] PPL Initial Comments at 15-17.

study date, rather than the estimated in-service date of the Long-Term Regional Transmission Facility.

870. In response to GridLab's request that the Commission clarify the distinction between the requirements for a minimum 20-year transmission planning horizon and a minimum 20-year benefits evaluation period,[1920] we reiterate the example provided in the NOPR whereby, if the Long-Term Regional Transmission Planning process identifies a Long-Term Regional Transmission Facility that is estimated to be in service in year 10 of the 20-year Long-Term Regional Transmission Planning horizon, then the estimate of benefits for that same facility will commence at year 10 and cover an additional 20 years. Thus, the requirement to use a 20-year transmission planning horizon is separate and distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from its estimated in-service date.

### 5. Evaluation of the Benefits of Portfolios of Transmission Facilities

#### a. NOPR Proposal

871. In the NOPR, the Commission proposed to provide transmission providers in each transmission planning region with the flexibility to propose to use a portfolio approach in the evaluation of benefits of regional transmission facilities through their Long-Term Regional Transmission Planning. Rather than mandating its use, the Commission

[1920] GridLab Initial Comments at 6-8.

encouraged the use of this approach by transmission providers.[1921] The Commission proposed to require transmission providers that propose to use a portfolio approach to include in their OATTs provisions describing how they would analyze the benefits of regional transmission facilities under such an approach and whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally or would be used only in certain specified instances.[1922]

**b. Comments**

**i. General Interest in the Use of Portfolios**

872. Most commenters who addressed the issue support the use of a portfolio approach to the evaluation of the benefits of regional transmission facilities in Long-Term Regional Transmission Planning, under which transmission providers would evaluate multiple transmission facilities in an aggregated, integrated fashion rather than doing so on a facility-by-facility basis.[1923] Exelon states that benefits assessments for portfolios are likely to be more robust and less sensitive to changes in study assumptions than project-

[1921] NOPR, 179 FERC ¶ 61,028 at PP 233-234.

[1922] *Id.* P 234.

[1923] *See, e.g.*, Acadia Center and CLF Initial Comments at 10; ACEG Initial Comments at 49; ACORE Initial Comments at 2; AEP Initial Comments at 6, 27-28; Ameren Initial Comments at 19; Clean Energy Associations Initial Comments at 10; Eversource Initial Comments at 25; Exelon Initial Comments at 15-16; Joint Consumer Advocates Initial Comments at 11; Massachusetts Attorney General Initial Comments at 15-16; Pacific Northwest State Agencies Initial Comments at 7; PG&E Initial Comments at 8; PJM Reply Comments at 23; PIOs Initial Comments at 28; TANC Initial Comments at 16; US DOE Initial Comments at 34-35.

by-project analyses, tend to have widely distributed benefits, which can help garner stakeholder support, and may provide for administrative efficiencies in transmission planning.[1924] ACEG states that portfolio planning more accurately evaluates the benefits that new transmission provides to the system.[1925] Georgia Commission states that evaluating transmission facilities collectively, rather than on a facility-by-facility basis, may provide a better picture of the benefits to each state or transmission planning region and result in a more robust selection of transmission facilities.[1926]

873. Renewable Northwest states that using portfolios in transmission planning is a best practice because it more completely captures systems benefits and leads to cost efficiencies.[1927] Renewable Northwest also comments that singularly focused planning processes often fail to identify the most cost-effective and efficient investments and instead have led to a bottom-up approach that has created a patchwork of transmission projects with high costs largely borne by ratepayers.[1928] EEI explains that the portfolio approach comprehensively addresses a number of transmission needs while ensuring a

[1924] Exelon Initial Comments at 15-16, 18 (citing NOPR, 179 FERC ¶ 61,028 at P 233).

[1925] ACEG Initial Comments at 49.

[1926] Georgia Commission Initial Comments at 7.

[1927] Renewable Northwest Initial Comments at 9-10 (citing Brattle-Grid Strategies Oct. 2021 Report at 23).

[1928] *Id.* at 9.

"no regrets" set of beneficial regional transmission projects.[1929] Eversource states that a portfolio approach can allow transmission providers to devise a set of transmission solutions that collectively create the most value compared to a piecemeal process.[1930]

874. AEP states that the portfolio approach offers three advantages: (1) it enables transmission planning regions to identify transmission projects with synergistic benefits across transmission planning regions because regions will be able to recognize the efficiencies of a collection of transmission projects that provide greater overall value to the grid together than they each provide on an individual basis; (2) there are administrative efficiencies; and (3) a portfolio approach best incorporates consideration of non-transmission alternatives and grid-enhancing technologies.[1931]

875. Numerous commenters point to the MISO Multi-Value Project process as an example of the successful use of portfolios.[1932] Clean Energy Associations state that the Multi-Value Project process has resulted in lower interconnection costs for generators as compared to transmission upgrades planned in response to interconnection requests.[1933] US DOE suggests the Multi-Value Project process is an example of the use of portfolios

[1929] EEI Initial Comments at 15.

[1930] Eversource Initial Comments at 25.

[1931] AEP Initial Comments at 27-28.

[1932] *See, e.g.*, EEI Initial Comments at 15; Clean Energy Associations Initial Comments at 10; MISO Initial Comments at 14; US DOE Initial Comments at 34-35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65-66).

[1933] Clean Energy Associations Initial Comments at 10.

to generate benefits that exceed costs.[1934] MISO states that it has worked with stakeholders to apply broad benefit metrics in the evaluation of Multi-Value Projects to identify portfolios of projects with benefits spread broadly throughout the region.[1935]

876. Some commenters believe that the Commission should require the use of portfolios in the evaluation of benefits of regional transmission facilities.[1936] US DOE supports requiring transmission planners to evaluate the benefits of proposed transmission facilities as a portfolio, rather than as individual investments, to reduce the uncertainty of estimating system-level benefits, to simplify cost allocation, and to reduce administrative burden.[1937] US DOE states that if the portfolio approach is inappropriate in a particular circumstance, the impacted entities could petition the Commission, on a case-by-case basis, to describe their proposed alternative approach.[1938]

877. New Jersey Commission states that the evidence from multiple studies of and experiences with long-term multi-driver and portfolio-based transmission planning

[1934] US DOE Initial Comments at 35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65-66).

[1935] MISO Initial Comments at 14.

[1936] Acadia Center and CLF Initial Comments at 4-5; ACEG Initial Comments at 31, 48-49; Cypress Creek Reply Comments at 8-9; ITC Initial Comments at 6, 23-24; Pattern Energy Initial Comments at 15-17; Pine Gate Initial Comments at 38-39; PIOs Initial Comments at 28; SEIA Initial Comments at 20-21; US DOE Initial Comments at 34-35; WATT Initial Comments at 8-9.

[1937] US DOE Initial Comments at 34-35.

[1938] *Id.* at 35.

proves that these approaches save ratepayers billions of dollars and failure to use them is *per se* unjust and unreasonable.[1939] Cypress Creek argues that a portfolio approach is essential to optimize benefits and reduce the likelihood of a state or agency derailing a transmission project with proven regional benefits.[1940]

878. PIOs state that the costs of a transmission project in a rural area that enhances access to renewable resources may exceed its benefits when evaluated alone, but, if evaluated with another project that relieves congestion, the two projects may support power flows that would not otherwise be possible.[1941] PIOs further state that portfolio planning can reduce the risk that transmission projects are underutilized because they were built for a single resource that is no longer used or only a narrow set of users were considered.[1942]

879. ITC argues that the Commission should mandate the use of a portfolio approach in RTO/ISOs to ensure that the most efficient, cost-effective, and broadly beneficial set of transmission projects are selected in each transmission planning cycle.[1943] ITC states that the use of a portfolio approach ensures that the greatest number of subregions within a transmission planning region receive benefits from each transmission planning cycle and

[1939] New Jersey Commission Initial Comments at 7.

[1940] Cypress Creek Reply Comments at 9.

[1941] PIOs Initial Comments at 31-32.

[1942] *Id.* at 36.

[1943] ITC Initial Comments at 6, 23-24.

provides significant efficiency gains because transmission providers can examine the whole portfolio to ensure that benefits exceed costs.[1944]

880. Pattern Energy urges the Commission to require transmission providers to adopt portfolio approaches and explain why a portfolio approach was not (or could not be) identified in any Long-Term Regional Transmission Plan when an incremental transmission solution is proposed.[1945] Pattern Energy suggests that, if the Commission does not require portfolios, it should set a voltage threshold to identify portfolio solutions and require that transmission providers must explain why a portfolio approach was not taken when proposing incremental transmission facilities at voltage levels above 100 kV.[1946] Similarly, Shell states that if the Commission does not require a portfolio approach, it should require transmission providers to explain why portfolios are not being used.[1947]

**ii. Interest in Flexibility in the Use of Portfolios**

881. Many other commenters assert that the Commission should only permit, not require, the use of portfolios in the evaluation of benefits.[1948] For example, Duke states

[1944] *Id.* at 23.

[1945] Pattern Energy Initial Comments at 15-17.

[1946] *Id.* at 17.

[1947] Shell Initial Comments at 16.

[1948] APPA Initial Comments at 32; Arizona Commission Initial Comments at 8; California Commission Initial Comments at 36-37; Dominion Initial Comments at 36; Duke Initial Comments at 25; Georgia Commission Initial Comments at 25; Michigan Commission Initial Comments at 8; MISO Initial Comments at 54; NARUC Initial

that a facility-by-facility approach may be better suited if Long-Term Scenarios reveal the same or nearly identical constraints in discrete and isolated areas of the transmission grid where upgrades would be beneficial, whereas if Long-Term Scenarios reveal more disparate issues in different scenarios a portfolio approach may be better suited to gaining consensus and allowing for more even distribution of benefits.[1949] Duke asks the Commission to provide that, on compliance, a transmission provider may document processes for switching between or using both a facility-by-facility analysis and a portfolio approach.[1950]

882. Dominion Energy states that some transmission providers may not have a portfolio of transmission projects to examine. NYISO asserts that transmission providers should not be required to mix and match components of different transmission developers' proposed transmission solutions to develop a portfolio to address a single transmission need.[1951] APPA and TANC urge the Commission to allow regional flexibility to use a portfolio approach to evaluate benefits.[1952]

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Comments at 27-29; Nebraska Commission Initial Comments at 7-8; NESCOE Initial Comments at 45; NYISO Initial Comments at 9, 41-42; PPL Initial Comments at 16-17; SDG&E Initial Comments at 3; SPP Initial Comments at 10; TANC Initial Comments at 16; TAPS Initial Comments at 14; Vermont State Entities Initial Comments at 7; Xcel Initial Comments at 12.

[1949] Duke Initial Comments at 25-26.

[1950] *Id.* at 25.

[1951] NYISO Initial Comments at 41.

[1952] APPA Initial Comments at 32; TANC Initial Comments at 16.

883. PPL argues that a portfolio approach should not be mandated because one-size-fits-all portfolio-based planning may have downsides and may not be applicable in all circumstances or transmission planning regions.[1953] PPL further states that relying on portfolios could lead to complications in siting and cost allocation.[1954] Relatedly, Michigan Commission argues that requiring portfolios could cause unnecessary delays for transmission projects that have strong stakeholder buy-in and incentivize including transmission projects less deserving of regional cost allocation purely to bolster assertions that all zones in multi-state RTOs/ISOs will benefit.[1955]

884. CAISO states that portfolio planning should be optional, arguing that CAISO's sequential transmission planning approach achieves multi-benefit and holistic objectives without requiring a portfolio approach.[1956] CAISO explains that a project-by-project review does not mean examining only one transmission need at a time or failing to consider transmission projects that meet multiple needs or deliver multiple benefits.[1957]

### iii. Interest in Including the Portfolio Approach in a Transmission Provider's OATT

885. In response to the Commission's proposal that a transmission provider that proposes a portfolio approach must include in its OATT a description of when it would

[1953] PPL Initial Comments at 16-17.

[1954] *Id.* at 17.

[1955] Michigan Commission Initial Comments at 8.

[1956] CAISO Reply Comments at 22.

[1957] *Id.* at 21-22.

use the approach and how it would analyze benefits, some commenters agree that even if use of portfolios is flexible, the Commission should have such a requirement.[1958] Vermont State Entities suggest that if a transmission provider elects to use a portfolio approach, it must include in its OATT a description of how it would use such an approach and whether that approach would be used universally or only in certain specified instances.[1959]

#### iv. Integrating Economic and Reliability Planning with Long-Term Regional Transmission Planning

886. PIOs state that portfolio planning is necessary and that the use of portfolios should incorporate long-term reliability and economic needs and benefits along with long-term Public Policy Requirements, because doing so allows transmission providers to select transmission projects with the higher benefit-to-cost ratios that resolve needs at least cost.[1960] PIOs state that by assessing all transmission needs at once and evaluating potential solutions, stakeholders will be able to find more efficient solutions that address multiple transmission needs that affect different jurisdictions simultaneously.[1961] PIOs ask that the final rule allow transmission providers to continue to address unforeseen short-term local reliability needs but establish a rebuttable requirement that all long-term

[1958] Clean Energy Associates Initial Comments at 14; NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 7.

[1959] Vermont State Entities Initial Comments at 7.

[1960] PIOs Initial Comments at 30-32.

[1961] *Id.* at 35.

economic, public policy, and regional reliability needs and benefits will be assessed on a portfolio basis in Long-Term Regional Transmission Planning.[1962]

887. SEPA states that the portfolio approach can be further enhanced by considering all categories of benefits: reliability, economic, public policy, and resilience.[1963] Likewise, SEIA states that the Commission should require portfolio-based planning that integrates all relevant factors, reliability, economic, and public policy, into Long-Term Regional Transmission Planning.[1964] Acadia Center and CLF discuss portfolio planning as integrating Long-Term Regional Transmission Planning with economic and reliability planning and state that the final rule should require portfolio-based planning that assesses economic, reliability, and other needs at the same time.[1965]

### v. Concerns with the Portfolio Approach

888. A few commenters express apprehension about the portfolio approach, including concerns that the use of portfolios may mask bad individual transmission projects in a portfolio or result in good transmission projects not being approved because of difficulties in obtaining multiple state approvals that may be necessary for a portfolio.[1966]

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[1962] PIOs Initial Comments at 32.

[1963] SEPA Initial Comments at 1.

[1964] SEIA Initial Comments at 20-21.

[1965] Acadia Center and CLF Initial Comments at 4-5.

[1966] CAISO Reply Comments at 24; Duke Initial Comments at 25-26; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 26; NARUC Initial Comments at 28; Pennsylvania Commission Initial Comments at 10; PPL Initial Comments at 17.

For example, Pennsylvania Commission states that a portfolio approach may cause siting concerns if a single transmission project in a portfolio is found by a state siting authority to be inconsistent with its state's public interest and siting regulations.[1967] Idaho Commission opposes requiring the use of a portfolio under any circumstances, stating that flexibility is necessary in transmission planning. It further states that a Commission requirement to use a portfolio approach under certain circumstances without specifying what these circumstances are could result in unjust and unreasonable rates.[1968] Louisiana Commission also opposes any requirement to use a portfolio approach and disagrees with the NOPR's encouragement of such an approach.[1969]

### c. Commission Determination

889. We adopt the NOPR proposal to allow, but not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities. Further, we adopt with modification the NOPR proposal to require transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities to include provisions in their OATTs regarding their use of the portfolio approach. While we adopt the NOPR proposal to require transmission providers to include provisions in their OATTs regarding their use of a portfolio approach, we do not

[1967] Pennsylvania Commission Initial Comments at 10.

[1968] Idaho Commission Initial Comments at 4.

[1969] Louisiana Commission Initial Comments at 26.

adopt the other proposed requirements. Specifically, we decline to adopt the NOPR proposal to require transmission providers to indicate whether a portfolio approach will be used universally or only in certain specified instances or to describe how they will analyze the benefits of regional transmission facilities under a portfolio approach. These requirements could impede transmission provider consideration and development of portfolio approaches. In response to Duke's request that the final rule provide transmission providers with the flexibility to switch between or use both facility-by-facility and portfolio approaches,[1970] we clarify that transmission providers may use either or both facility-by-facility and portfolio approaches within the same Long-Term Regional Transmission Planning cycle.

890. We find that there are numerous advantages to a portfolio approach to evaluating benefits, including administrative efficiencies related to economies of scale and a more stable or even distribution of benefits that may result from a portfolio evaluation, which is likely to facilitate agreement on regional cost allocation. However, these advantages must be balanced against other considerations, and we therefore find that providing transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach is appropriate. Accordingly, we decline the request of some commenters[1971] to require transmission providers to use a portfolio approach.

[1970] Duke Initial Comments at 25-26.

[1971] Acadia Center and CLF Initial Comments at 4-5; ACEG Initial Comments at 31, 48-49; Cypress Creek Reply Comments at 8-9; ITC Initial Comments at 6, 23-24; Pattern Energy Initial Comments at 16-18; Pine Gate Initial Comments at 38-39; PIOs Initial Comments at 28; SEIA Initial Comments at 20-21; US DOE Initial Comments at

### 6. Issues Related to Use of Benefits

#### a. NOPR Proposal

891. The Commission in the NOPR declined, consistent with Order No. 1000, to propose to prescribe any particular definition of "benefits" or "beneficiaries."[1972]

#### b. Comments

892. Some commenters request specific definitions for the terms "benefits" or "beneficiaries" or offer guidance on definitions.[1973] NASUCA urges the Commission not to define benefits so broadly that every transmission project would qualify to be built, stating that overly broad benefit definitions reduce any rational relationship between cost allocation and identifiable beneficiaries.[1974]

893. In contrast, other commenters agree with the Commission's proposal not to define "benefits" or "beneficiaries."[1975] For example, OMS and the Indiana Commission express support for the NOPR proposal to allow for flexibility in determining the

34-35; WATT Initial Comments at 8-9.

[1972] NOPR, 179 FERC ¶ 61,028 at P 183 & n.324 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 624-625).

[1973] ELCON Initial Comments at 14-15; NASUCA Initial Comments at 10.

[1974] NASUCA Initial Comments at 10.

[1975] APPA Initial Comments at 31-33; Clean Energy Buyers Reply Comments at 9; Georgia Commission Initial Comments at 6-7; Indiana Commission Initial Comments at 6-7; Louisiana Commission Reply Comments at 9-10; Nebraska Commission Initial Comments at 7; TANC Initial Comments at 16; US Chamber of Commerce Initial Comments at 7-8.

definitions of benefits and beneficiaries for the purpose of selecting transmission facilities in Long-Term Regional Transmission Planning.[1976]

894. Some commenters call for a state role in identifying benefits or metrics for use in Long-Term Regional Transmission Planning.[1977] California Commission states that the Commission should require transmission providers to demonstrate that they consulted with the Relevant State Entities in their transmission planning region regarding benefits metrics.[1978] California Commission further states that the Commission should require transmission providers to indicate in their compliance filings whether their proposed benefits and metrics are supported by the Relevant State Entities, as well as to explain any points of disagreement.[1979] Likewise, New York Commission and NYSERDA state that, especially in single-state RTOs/ISOs, the state should be afforded a central role in determining the benefits that transmission providers will consider and the metrics for quantifying them.[1980]

[1976] Indiana Commission Initial Comments at 6-7; OMS Initial Comments at 13.

[1977] California Commission Initial Comments at 35; Massachusetts Attorney General Initial Comments at 14; Michigan Commission Initial Comments at 7-8; NESCOE Initial Comments at 41-43; North Carolina Commission and Staff Initial Comments at 6; PJM Market Monitor Initial Comments at 4.

[1978] California Commission Initial Comments at 35.

[1979] *Id.*

[1980] New York Commission and NYSERDA Initial Comments at 8.

895. North Carolina Commission and Staff state that, given the focus of the NOPR on transmission needs driven by changes in the generation mix and demand, which are areas of state jurisdiction, the Commission should require state agreement at every stage of the Long-Term Regional Transmission Planning process from identification of transmission needs, to the evaluation of the benefits of regional transmission facilities to meet those needs, to establishment of selection criteria, and finally to establishment of a cost allocation method.[1981] Similarly, NESCOE explains that, while transmission providers have the technical expertise to identify, calculate, and explain the benefits that a given transmission facility may provide, states must be involved where state laws and policies are the project drivers.[1982] As such, NESCOE requests that the Commission require that transmission providers either elevate and codify the states' role in all four phases of Long-Term Regional Transmission Planning or explain how and why, following consultation with the Relevant State Entities, the transmission provider developed a different approach.[1983] NESCOE asserts that this requirement would ensure that states, if they so elect, have a defined role in the evaluation phase of Long-Term Regional Transmission Planning.[1984]

[1981] North Carolina Commission and Staff Initial Comments at 6.

[1982] NESCOE Initial Comments at 41-43.

[1983] *Id.* at 9-10, 41-43.

[1984] *Id.* at 41-43.

896. Virginia Commission Staff contends that the NOPR-identified benefits should be used only if affected states agree to their use.[1985] PJM Market Monitor agrees that it makes sense to attempt an evaluation of a broad set of benefits and beneficiaries through increased state involvement.[1986]

897. Michigan Commission asserts that state regulators should be afforded substantial deference in identifying what benefit metrics and calculation methods should be used to justify long-term transmission plans, arguing that states with objections or concerns that an approved benefit metric is too speculative or otherwise inappropriate may find it more challenging to justify ratepayer investments and land condemnation in state siting proceedings.[1987] Massachusetts Attorney General states that the Commission should require that transmission providers establish an open and transparent process that provides states and other stakeholders with a meaningful opportunity to participate in the process of identifying the benefits to be used in Long-Term Regional Transmission Planning and determining how such benefits will be calculated.[1988] Several commenters state that decisions regarding benefit determination, metrics, and implementation of metrics should be made in coordination with all stakeholders.[1989] NRECA and Vermont

[1985] Virginia Commission Staff Initial Comments at 5.

[1986] PJM Market Monitor Initial Comments at 4.

[1987] Michigan Commission Initial Comments at 7-8.

[1988] Massachusetts Attorney General Initial Comments at 14.

[1989] NYISO Initial Comments at 37; NRECA Initial Comments at 46; Vermont

State Entities assert that transmission providers should be required to demonstrate that all stakeholders are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term Regional Transmission Planning.[1990]

898. PPL stresses the important role that states play in siting transmission facilities and the significance of benefits from transmission facilities in this process, cautioning that differences between states' and the Commission's delineation and evaluation of benefits will result in great uncertainty. PPL asserts that this uncertainty could lead to abandoned projects, costly litigation, and a largely underutilized planning tool, akin to transmission projects driven by public policy needs under Order No. 1000.[1991]

899. In contrast, ACORE notes that the benefits of transmission facilities are often spread out among states regardless of the state policies contributing to the need for such transmission facilities.[1992]

900. SoCal Edison urges the Commission not to decouple policy projects from reliability and economic projects in transmission planning, so as to reduce barriers to

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State Entities Initial Comments at 6.

[1990] NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

[1991] PPL Initial Comments at 14-15.

[1992] ACORE Initial Comments at 12; ACORE Reply Comments at 6.

regional coordination and ensure analysis of all potential benefits of a transmission project.[1993]

901. Indiana Commission states that it supports the NOPR proposal as long as the final rule provides for an equitable cost allocation method that allocates costs to the cost causer and beneficiaries of regional transmission development.[1994]

### c. Commission Determination

902. Consistent with the NOPR, we continue to decline to define "benefits" or "beneficiaries." We discuss above descriptions of the seven required benefits, and we further require transmission providers to propose a method to measure each of those benefits. These descriptions and requirements for these seven benefits will facilitate transparency regarding the use of benefits in Long-Term Regional Transmission Planning and represent an improvement in this respect over Order No. 1000, which lacked such descriptions.[1995] However, we do not believe that establishing a definition of "benefits" or "beneficiaries" would significantly improve upon these descriptions and we are concerned that any such definition could inadvertently exclude benefits and beneficiaries.

903. We acknowledge comments requesting greater clarity regarding states' roles in determining benefits in their transmission planning regions and regarding the benefits

[1993] SoCal Edison Initial Comments at 12-13.

[1994] Indiana Commission Initial Comments at 6-7.

[1995] As noted above, we do not require transmission providers to include additional benefits that they use for purposes of evaluation and selection of Long-Term Regional Transmission Facilities in their OATTs.

that will be used by transmission providers in Long-Term Regional Transmission Planning, including NRECA's and Vermont State Entities' assertions that transmission providers should be required to demonstrate that all stakeholders (including state entities and load-serving entities) are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term Regional Transmission Planning.[1996] In response, we note this final rule provides transmission providers with flexibility as to how they measure the seven required benefits, as well as flexibility to use additional benefits beyond the seven that we require. Consistent with other reforms in this final rule incorporating an inclusive role for states in transmission planning, we encourage transmission providers to consult with states as they develop proposals to comply with the requirements of this final rule and consider whether, and if so, how, to use additional benefits in Long-Term Regional Transmission Planning.[1997]

## E. Evaluation and Selection of Long-Term Regional Transmission Facilities

### 1. Requirement to Adopt an Evaluation Process and Selection Criteria

#### a. NOPR Proposal

904. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a transparent and not unduly discriminatory evaluation process and criteria to identify and

[1996] NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

[1997] *See supra* Other Benefits section.

evaluate transmission facilities (or portfolios of transmission facilities) for potential selection that address transmission needs driven by changes in the resource mix and demand.[1998] The Commission preliminarily found that the development and analysis of Long-Term Scenarios cannot remedy the deficiencies in the Commission's existing regional transmission planning requirements without the inclusion of such an evaluation process and selection criteria because, without them, transmission providers' Commission-jurisdictional rates may be unjust and unreasonable and unduly discriminatory and preferential.[1999]

905. The Commission further proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

**b. Comments**

906. Many commenters support the Commission's proposal to require transmission providers to include in their OATTs provisions providing criteria that they will use to identify and evaluate transmission facilities for potential selection to address transmission needs driven by changes in the resource mix and demand.[2000] For example, Pacific

[1998] *See* NOPR, 179 FERC ¶ 61,028 at PP 241-242.

[1999] *Id.* P 250.

[2000] ACEG Initial Comments at 9; ACORE Initial Comments at 14; Amazon Initial Comments at 9; Ameren Initial Comments at 20; APPA Initial Comments at 33; CARE

Northwest State Agencies argue that this reform is critical to ensuring that Long-Term Regional Transmission Planning results in appropriate modeling and evaluation of Long-Term Regional Transmission Facilities.[2001] ACEG contends that transparent selection processes are key to reducing conflict (including costly litigation), developing legally sustainable long-term regional transmission plans, and maximizing benefits over time to consumers without over-building transmission facilities.[2002]

907. Other commenters oppose the Commission's proposal. Many of these commenters argue that Long-Term Regional Transmission Planning should be for informational purposes only and that the Commission should not require transmission providers to include selection criteria in their OATTs.[2003] Alabama Commission contends that Long-Term Regional Transmission Planning should not involve selection

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Coalition Initial Comments at 11-12; Clean Energy Buyers Initial Comments at 22; Exelon Initial Comments at 17; GridLab Initial Comments at 19; NRECA Initial Comments at 25; Ørsted Initial Comments at 5-6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 18; Resale Iowa Initial Comments at 7-8.

[2001] Pacific Northwest State Agencies Initial Comments at 19.

[2002] ACEG Initial Comments at 9, 58.

[2003] Alabama Commission Initial Comments at 3; ELCON Initial Comments at 10; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23-24; NRG Initial Comments at 6, 14; Ohio Consumers Initial Comments at 20; *see also* NARUC Initial Comments at 5 ("Long-Term Regional Transmission Planning [should] be used as a planning tool and not a construction requirement."); TANC Initial Comments at 10 (commenting that TANC "requests that the Commission clarify[] that the Commission is not proposing to require use of a 20-year planning horizon for . . . selecting Long-Term Regional Transmission Facilities").

or construction obligations unless the affected state regulators support such actions.[2004] ELCON argues that selection should occur in "nearer-term planning (*i.e.* 10-15 years)" when there is greater certainty that there is a specific transmission need.[2005]

908. Some commenters argue that it is unnecessary for the Commission to require that transmission providers include additional selection criteria in their OATTs. For example, Dominion contends that Order No. 1000 already requires transmission providers to include selection criteria in their OATTs, and that the final rule should allow, but not require, them to add to those existing selection criteria.[2006] Idaho Commission also believes that Order No. 1000's requirements are adequate and argues that the Commission has not demonstrated that there is a need to modify them.[2007] Similarly, Idaho Power argues that selection criteria specific to Long-Term Regional Transmission Planning are unnecessary in light of existing processes to identify and evaluate transmission facilities in the NorthernGrid transmission planning region.[2008] NYISO requests that the Commission confirm that the final rule will not require changes to or the

[2004] Alabama Commission Initial Comments at 3. Relatedly, Avangrid argues that the Commission should more clearly articulate how selection affects the actual construction of the transmission facility. Avangrid Initial Comments at 17.

[2005] ELCON Initial Comments at 10-11.

[2006] Dominion Initial Comments at 37 (citing NOPR, 179 FERC ¶ 61,028 at P 236).

[2007] Idaho Commission Initial Comments at 4-5.

[2008] Idaho Power Initial Comments at 8.

replacement of existing selection criteria.[2009] Chemistry Council argues that the Commission should affirm that transmission providers must continue addressing nearer-term regional transmission needs, giving significant weight to transmission facilities that meet customer and end-user needs, ensure grid reliability and energy security, and prevent abandonment of needed resources.[2010]

909. Clean Energy Buyers state that they support the NOPR proposal to grant eligibility to use the applicable cost allocation method to the developer of a Long-Term Regional Transmission Facility selected, subject to applicable development schedules. Clean Energy Buyers argue that this proposal could provide a more stable source of revenue and help resolve the "first-mover problem," which in turn could support additional transmission development.[2011]

910. Finally, SPP contends that allowing transmission providers to include selection criteria in business practice manuals rather than their OATTs would give them more flexibility if they need to adjust study approaches.[2012]

[2009] NYISO Initial Comments at 43.

[2010] Chemistry Council Initial Comments at 6-7.

[2011] Clean Energy Buyers Initial Comments at 21-22 (citing NOPR, 179 FERC ¶ 61,028 at P 247).

[2012] SPP Initial Comments at 21-22.

### c. Commission Determination

911. We adopt the NOPR proposal to require transmission providers in each transmission planning region to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs. We set forth requirements with respect to the evaluation process and selection criteria in the following sections.

912. We also adopt the NOPR proposal that, consistent with Order No. 1000, the transmission developer of a Long-Term Regional Transmission Facility that is selected, whether incumbent or nonincumbent, will be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

913. As explained above, transmission providers currently are not identifying or evaluating Long-Term Regional Transmission Facilities that might more efficiently or cost-effectively address Long-Term Transmission Needs and, therefore, do not have the opportunity to select such transmission facilities. We find that remedying these deficiencies in the Commission's existing regional transmission planning requirements requires the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities, as outlined below, which, together with other aspects of this final rule, will help to ensure that transmission providers' Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

914. We find that the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities is essential to the reforms that we adopt in this final rule. Without these essential components, Long-Term Regional Transmission Planning would merely inform the existing regional transmission planning processes rather than solving the deficiencies in the Commission's existing regional transmission planning requirements that we identify in this final rule. The complete set of reforms that we adopt here are fundamental to resolving these deficiencies and to ensuring that transmission providers have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs. Therefore, we disagree with commenters who suggest that an evaluation process or selection criteria are unnecessary or inappropriate for the Long-Term Regional Transmission Planning[2013] reforms that we adopt in this final rule.

915. We understand that transmission providers might propose to re-purpose existing evaluation processes or selection criteria (with or without modifications thereto) to use in Long-Term Regional Transmission Planning. In their compliance filings, transmission providers must propose the evaluation process and selection criteria that they will use in Long-Term Regional Transmission Planning, and they must demonstrate that they meet

[2013] *See, e.g.*, Alabama Commission Initial Comments at 3; Dominion Initial Comments at 37; ELCON Initial Comments at 10-11; Idaho Commission Initial Comments at 4-5; Idaho Power Initial Comments at 8; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23-24; NRG Initial Comments at 6, 14; TANC Initial Comments at 10; *see also* Ohio Consumers Initial Comments at 20 (arguing that a 20-year transmission planning horizon is inappropriate for constructing or allocating the costs of transmission facilities).

the final rule requirements. In response to NYISO's request,[2014] however, we clarify that nothing in this final rule requires transmission providers to modify or replace selection criteria used in their existing reliability and economic Order No. 1000 regional transmission planning processes.

916. As discussed below, to meet the requirements of this final rule, transmission providers in each transmission planning region must establish a Long-Term Regional Transmission Planning evaluation process that: (1) identifies Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs; (2) measures the benefits of the identified Long-Term Regional Transmission Facilities consistent with the final rule requirements; and (3) designates a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[2015] We recognize the inherent uncertainty involved in identifying Long-Term Transmission Needs over the minimum transmission planning horizon adopted in this final rule and in measuring the benefits that could be provided by Long-Term

[2014] NYISO Initial Comments at 43. We reiterate that, as discussed above in the Participation in Long-Term Regional Transmission Planning section, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements, provided that transmission providers demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final rule.

[2015] *See, e.g.*, NOPR, 179 FERC ¶ 61,028 at P 56 (setting forth requirements for Long-Term Regional Transmission Planning).

Regional Transmission Facilities. However, we continue to believe that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that minimize these risks while allowing for selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet Long-Term Transmission Needs. We emphasize that we do not require transmission providers to select any particular Long-Term Regional Transmission Facilities but rather to adopt an evaluation process and selection criteria that meet the final rule requirements. This evaluation process will ensure that Long-Term Regional Transmission Planning will provide transmission providers with a framework that allows for the selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.[2016]

917. We reiterate that, consistent with Order No. 1000,[2017] selection in the regional transmission plan does not entitle the transmission developer of a selected Long-Term Regional Transmission Facility to site or construct that transmission facility, nor does it obviate the need for the transmission developer to obtain other state, local, and/or federal

[2016] For these reasons, in addition to those discussed above, we disagree with ELCON that transmission providers should only select transmission facilities in "near-term planning (*i.e.* 10-15 years)." ELCON Initial Comments at 10-11.

[2017] *E.g.*, Order No. 1000-A, 139 FERC ¶ 61,132 at P 191.

permits or authorizations. For this reason, we disagree with comments suggesting that the Commission proposed to do otherwise in the NOPR.[2018]

918. Finally, we find that, consistent with the Commission's rule of reason,[2019] transmission providers' evaluation processes and selection criteria significantly affect rates, are reasonably susceptible to specification, and are not otherwise so generally understood as to render their recitation superfluous and therefore must be included in their OATTs. As such, we reject SPP's request that we allow transmission providers to instead maintain evaluation processes and selection criteria in their business practice manuals.[2020]

### 2. Flexibility

#### a. NOPR Proposal

919. Subject to certain minimum requirements, the Commission proposed in the NOPR to provide transmission providers with the flexibility to propose the selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective regional transmission facilities to address the region's transmission needs

[2018] *See, e.g.*, Alabama Commission Initial Comments at 3; Dominion Reply Comments at 8 (citing PIOs Initial Comments at 28; NARUC Initial Comments at 5-6, 39); NARUC Initial Comments at 5, 39.

[2019] *See Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210, at P 183 (2023) (citing *Hecate Energy Greene Cnty. 3 LLC v. FERC*, 72 F.4th 1307, 1314 (D.C. Cir. 2023); *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985)).

[2020] SPP Initial Comments at 21-22.

driven by changes in the resource mix and demand ultimately are selected.[2021] The Commission stated that this proposed flexibility would help accommodate regional differences, such as differences in transmission needs, factors driving those needs, and market structures.[2022] The Commission stated that providing flexibility to propose evaluation processes and selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.[2023] The Commission stated that it further believed this proposed flexibility would allow transmission providers in each transmission planning region to develop selection criteria that could sufficiently balance individual state interests within each transmission planning region.[2024]

**b. Comments**

920. Many commenters support the Commission's proposal to provide transmission providers with the flexibility to propose an evaluation process and selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities to address the transmission

[2021] NOPR, 179 FERC ¶ 61,028 at P 242.

[2022] *Id.* P 243.

[2023] *Id.* P 243.

[2024] *Id.* P 244.

planning region's transmission needs driven by changes in the resource mix and demand ultimately are selected.[2025]

921. For example, Nebraska Commission asserts that this flexibility will allow transmission providers to develop selection criteria that balance individual states' interests.[2026] Eversource argues that flexibility will foster investments in cost-effective regional transmission facilities, accommodate differences in transmission needs between transmission planning regions, and encourage stakeholder engagement.[2027] While NEPOOL supports flexibility as a general matter, it asserts that the Commission should articulate guiding principles for how selection decisions will be made and by whom, and guidelines regarding when transmission solutions should be selected to address long-term transmission needs.[2028]

922. By contrast, some commenters argue that the Commission should establish *pro forma* selection criteria.[2029] Clean Energy Associations argues that doing so would

[2025] APPA Initial Comments at 33-34; Avangrid Initial Comments at 17; California Commission Initial Comments at 37; Chemistry Council Initial Comments at 6; Duke Initial Comments at 26; Eversource Initial Comments at 26; GridLab Initial Comments at 19; ISO-NE Initial Comments at 35; MISO Initial Comments at 54; Nebraska Commission Initial Comments at 8; TAPS Initial Comments at 16; US Chamber of Commerce Initial Comments at 8.

[2026] Nebraska Commission Initial Comments at 8 (citing NOPR, 179 FERC ¶ 61,028 at P 244).

[2027] Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at PP 242-243).

[2028] NEPOOL Initial Comments at 7-8.

[2029] *See, e.g.*, ACORE Reply Comments at 5-6 (citing Policy Integrity Initial

enhance transparency, minimize differences across seams, and enable state regulators, consumers, and other market participants to evaluate transmission projects that result from Long-Term Regional Transmission Planning on an apples-to-apples basis.[2030] Similarly, SEIA urges the Commission to establish a set of minimum requirements for selecting transmission facilities in Long-Term Regional Transmission Planning, arguing that transmission planning regions otherwise may fail to select transmission facilities that provide significant regional benefits.[2031] For its part, Clean Energy Buyers contends that adopting *pro forma* selection criteria would provide greater transparency and consistency across transmission planning regions, hopefully help to avoid disputes, and allow for consultation with states and other stakeholders.[2032]

923. Acadia Center and CLF argue that requiring a minimum set of selection criteria will provide critical information to transmission providers who rely on the Commission to make clear what considerations they may weigh in Long-Term Regional Transmission Planning, facilitating more productive conversations at the regional level.[2033]

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Comments at 2-3); Policy Integrity Initial Comments at 2-3.

[2030] Clean Energy Associations Initial Comments at 22-23.

[2031] SEIA Initial Comments at 5, 19.

[2032] Clean Energy Buyers Initial Comments at 22-23.

[2033] Acadia Center and CLF Initial Comments at 10-11.

### c. Commission Determination

924. Subject to the requirements described further below, we adopt the NOPR proposal to require transmission providers in each transmission planning region to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria, that they believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address the transmission planning region's Long-Term Transmission Needs. We believe that providing transmission providers with this flexibility will allow them to design evaluation processes and selection criteria that can accommodate regional differences.

925. We reject requests that, instead of providing transmission providers with flexibility, we set forth standard evaluation processes and selection criteria in this final rule that transmission providers would be required to adopt.[2034] While we recognize that there may be some benefits to doing so, we also find that transmission planning regions have different transmission needs and market structures that make designing a standard evaluation process and selection criteria difficult.

926. In response to NEPOOL,[2035] we clarify that transmission providers make the selection decisions in Long-Term Regional Transmission Planning. Although we do not require transmission providers to select any particular Long-Term Regional Transmission

[2034] Acadia Center and CLF Initial Comments at 10-11; Clean Energy Associations Initial Comments at 22-23; SEIA Initial Comments at 5, 19.

[2035] NEPOOL Initial Comments at 8.

Facility to address Long-Term Transmission Needs, as discussed below in the No Selection Requirement section, we do set forth minimum requirements with respect to the evaluation process and selection criteria, which will help to ensure that transmission providers select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address Long-Term Transmission Needs.

### 3. Minimum Requirements

#### a. NOPR Proposal

927. In the NOPR, the Commission proposed certain minimum requirements such that transmission providers' selection criteria must (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.[2036] The Commission noted that, to comply with the Order Nos. 890 and 1000 transmission planning principles, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.[2037] The Commission stated that the evaluation process and,

[2036] NOPR, 179 FERC ¶ 61,028 at PP 241-242, 245.

[2037] *Id.* P 242 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328).

specifically, the selection criteria, must seek to maximize benefits to consumers over time without over-building transmission facilities.[2038]

928. The Commission stated that providing flexibility to propose selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.[2039] The Commission also stated that transmission providers would have the flexibility to propose to use a portfolio approach in selecting regional transmission facilities that address transmission needs driven by changes in the resource mix and demand.[2040] The Commission proposed to require transmission providers that propose such an approach to include in their OATTs provisions describing whether the selection criteria would apply to one proposed regional transmission facility or to a portfolio of regional transmission facilities, as well as whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in the resource mix and demand or would be used only in certain specified instances.[2041]

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[2038] *Id.*

[2039] *Id.* P 243.

[2040] *Id.* P 249.

[2041] *Id.*

929. The Commission recognized the inherent uncertainty involved in predicting future transmission needs, including those driven by changes in the resource mix and demand, as well as the concerns that many commenters expressed in response to the ANOPR that imperfect information may lead to selecting transmission facilities that become stranded assets.[2042] The Commission also stated that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that could minimize these risks while allowing for investment in transmission facilities that more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand.[2043] The Commission noted that under a "least-regrets" approach, for example, transmission providers in a transmission planning region would select a transmission facility (or portfolio of transmission facilities) that is net-beneficial in most or all Long-Term Scenarios, even if other transmission facilities have more net benefits or a higher benefit-cost ratio in a single Long-Term Scenario. The Commission stated that another approach is a "weighted-benefits approach," in accordance with which transmission providers in a transmission planning region would select a transmission facility (or portfolio of regional transmission facilities) based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario studied.[2044]

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[2042] *Id.* P 251.

[2043] *Id.*

[2044] *Id.* (citing Brattle-Grid Strategies Oct. 2021 Report at 59-60).

**b. Comments**

930. Commenters make a wide variety of arguments with respect to the minimum requirements that the Commission should impose with respect to evaluation processes and selection criteria. Many commenters support the Commission's proposal to require that selection criteria: (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.[2045]

931. Some commenters generally support the Commission's proposal with certain modifications. For example, Ameren argues that requiring selection criteria to maximize benefits to consumers over time without over-building transmission facilities is highly subjective, because such a requirement could refer to maximizing gross or net benefits and because certain interpretations could override the consideration of costs.[2046] Vistra likewise argues that the directive to maximize benefits to consumers over time without over-building transmission facilities is unhelpfully vague and that maximizing benefits

[2045] *See* ACEG Initial Comments at 58-59; ACORE Initial Comments at 14; Amazon Initial Comments at 9; APPA Initial Comments at 33-34; CARE Coalition Initial Comments at 11-12; NESCOE Initial Comments at 46; NRECA Initial Comments at 25; Ørsted Initial Comments at 5-6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 17-18; TAPS Initial Comments at 16.

[2046] Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at P 243 n.390).

should not be understood to disregard costs.[2047] WATT Coalition states that the Commission should require maximization of net benefits and cautions that it would be unjust and unreasonable to ignore benefits or costs in the assessment of options.[2048]

932. GridLab argues that selection criteria should seek to manage uncertainty and risk, stating that the Commission should clarify that the criteria must address not only the risk of over-building but also of under-building transmission.[2049] In contrast, New York State Department argues that selection criteria should be designed to minimize the financial risk to ratepayers of over-building the transmission system.[2050] NYISO requests clarification on the definition of over-building and argues that the final rule should provide additional guidance on how transmission planning regions should address this risk. NYISO contends that the final rule should treat the risk of over-building as an additional qualitative criterion that transmission planning regions should consider, as informed by open and transparent stakeholder review.[2051]

933. EEI contends that it is appropriate for the Commission to provide guidance by providing non-mandatory factors for transmission planning regions to consider.[2052]

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[2047] Vistra Initial Comments at 17-18.

[2048] WATT Coalition Initial Comments at 9.

[2049] GridLab Initial Comments at 19.

[2050] New York State Department Initial Comments at 4.

[2051] NYISO Initial Comments at 43.

[2052] EEI Initial Comments at 45-46.

ELCON argues that transparency with respect to selection criteria requires that the criteria and their proper weighting must be clear and easily accessible to consumers through transmission providers' OASIS and OATT.[2053]

934. Commenters make several arguments with respect to the metrics that the Commission should allow or require transmission providers to use when evaluating whether to select Long-Term Regional Transmission Facilities. For example, some commenters argue that transmission providers should select transmission facilities by using metrics that seek to maximize net benefits instead of ones that rely on benefit-cost ratios.[2054] ACEG argues that the Commission can require metrics that seek to maximize net benefits using the same authority it relied upon in promulgating Order No. 1000.[2055]

935. Breakthrough Energy states that, while metrics such as benefit-cost ratios are useful indicators, the efficient solution is the one that maximizes net benefits.[2056] WATT Coalition contends that, in Australia, the transmission planner lists all transmission facility alternatives ranked by the net present value of the consumer benefits that the

[2053] ELCON Initial Comments at 17.

[2054] ACEG Initial Comments at 49-50; Breakthrough Energy Initial Comments at 23; Clean Energy Associations Initial Comments at 22; DC and MD Offices of People's Counsel Initial Comments at 33; Evergreen Action Initial Comments at 4; ITC Initial Comments at 25; WATT Coalition Initial Comments at 9.

[2055] *See* ACEG Initial Comments at 49-50 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 58).

[2056] Breakthrough Energy Initial Comments at 23.

alternatives would provide, and selects the option that provides the most benefits in the absence of a compelling reason not to do so.[2057]

936. MISO argues that selection criteria should maximize long-term transmission value, defined as the difference between total benefits and total costs on a present value basis over a pre-determined transmission planning horizon.[2058] MISO contends that using such a metric is important when benefit-cost ratios are high and transmission expansion is substantial, as many of the benefits provided by new transmission facilities are difficult to quantify in terms of dollars despite providing significant qualitative benefits.[2059] Relatedly, CTC Global argues that selecting transmission facilities with the lowest capital costs is no longer a best practice, in light of increased debate in many RTOs/ISOs about issues such as mandated resource mixes, compensation in capacity markets, transmission planning criteria and cost allocation, and carbon taxes.[2060] CTC Global asserts that, if a transmission project is selected with least capital cost as a selection criterion, consumers will pay higher energy costs and higher total costs than what they would pay if the

[2057] WATT Coalition Initial Comments at 9.

[2058] MISO Initial Comments at 55-56.

[2059] *Id.*

[2060] CTC Global Initial Comments at 6-7 (citing *State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021) (Christie, Comm'r, concurring at PP 4-5)).

Commission were to require transmission providers to evaluate the NOPR's proposed benefits as well as cost.[2061]

937. Commenters also offer a variety of perspectives regarding benefit-cost ratios. Clean Energy Associations recommend that, if the Commission continues to allow benefit-cost ratios, such ratios not exceed Order No. 1000's maximum allowable benefit-cost ratio of 1.25-to-1.00.[2062] ITC argues that, if the Commission allows transmission providers to use benefit-cost ratios, it should require the use of a 1.00-to-1.00 benefit-cost ratio for the evaluation of candidate portfolios.[2063] Cypress Creek asserts that the Commission should retain the maximum permitted benefit-cost ratio of 1.25-to-1.00 and consider lowering that threshold to 1.00-to-1.00 because a transmission facility with a benefit-cost ratio of at least 1.00-to-1.00 is beneficial.[2064]

938. Pattern Energy argues that the existing maximum 1.25-to-1.00 allowable benefit-cost ratio is too high for purposes of Long-Term Regional Transmission Planning. Pattern Energy explains that scenarios and sensitivities typically are created to bookend what the future may look like, and those bookends are often weighted lower than a "business as usual" scenario. In this context, Pattern Energy argues that a lower benefit-

[2061] *Id.* at 9.

[2062] Clean Energy Associations Initial Comments at 22.

[2063] ITC Initial Comments at 25-26.

[2064] *See* Cypress Creek Reply Comments at 8 & n.14 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 646).

to-cost ratio is necessary because the standard to approve transmission facilities is so high that transmission ratepayers are not receiving an appropriate opportunity to realize the value of new transmission infrastructure. Pattern Energy suggests that a more reasonable benefit-cost ratio would be 1.10-to-1.00 but notes that a higher benefit-to-cost ratio may be appropriate to evaluate a portfolio of transmission facilities (e.g., 1.15 – 1.25).[2065]

939. By contrast, New York State Department asserts that transmission providers should not select a transmission facility unless benefits in the long term greatly exceed costs and that adopting a much higher benefit-cost ratio than the existing 1.25 standard may be required (e.g., 2.25-to-1.00).[2066]

940. Some commenters express support for least-regrets[2067] or weighted-benefits approaches[2068] to selecting transmission facilities in Long-Term Regional Transmission

[2065] Pattern Energy Initial Comments at 14-15.

[2066] New York State Department Initial Comments, Montalvo Aff. at 14-15.

[2067] *See* Avangrid Initial Comments at 10-11; Eversource Initial Comments at 26-27; Exelon Initial Comments at 18; GridLab Initial Comments at 19-20; National Grid Initial Comments at 11-12; NRECA Initial Comments at 48; PG&E Initial Comments at 6.

[2068] *See* ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59-60; Derek Stenclik and Ryan Deyoe, *Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force*, Energy Systems Integration Group, 37 (June 2022), https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf) (Energy Systems Integration Group June 2022 Report)); Clean Energy Associations Initial Comments at 22 (citing NOPR, 179 FERC ¶ 61,028 at P 251).

Planning. For example, National Grid argues that identifying least-regrets transmission facilities should be the goal of Long-Term Regional Transmission Planning.[2069]

941. Avangrid explains that "no regrets" or "low regrets" transmission facilities are those that likely will be needed under multiple scenarios and a broad range of assumptions.[2070] PG&E agrees and argues that these transmission facilities are most likely to realize projected benefits.[2071] PG&E states that transmission facilities that provide more limited benefits or benefits under a limited number of scenarios may require additional study and should not be selected until there is more certainty that their benefits will be realized.[2072]

942. Exelon also advocates for a least-regrets approach, arguing that it minimizes risk and maximizes value for customers and transmission owners.[2073] Eversource contends that a least-regrets approach is most likely to build the consensus among stakeholders that can support transmission facilities through planning, financing, siting, and cost

[2069] National Grid Initial Comments at 11-12 (citing National Grid ANOPR Initial Comments at 16).

[2070] Avangrid Initial Comments at 10-11.

[2071] PG&E Initial Comments at 6.

[2072] *Id.*

[2073] Exelon Initial Comments at 18.

allocation.[2074] NRECA argues that a least-regrets approach will help mitigate the risk that consumers will pay for unnecessary transmission facilities.[2075]

943. ACORE recommends the use of a weighted-benefits approach, which ACORE argues has been endorsed in recent expert reports on transmission planning.[2076] Dominion sees promise in both least-regrets and weighted-benefits approaches but argues that requiring transmission providers to propose specific selection criteria may result in litigation, delay, and increased costs.[2077]

944. New England for Offshore Wind argues that the Commission should require transmission providers to give preference to transmission facilities that perform well under a range of scenarios.[2078] A number of commenters caution, however, that the Commission should allow transmission providers to select transmission facilities even where they are not net-beneficial in every Long-Term Scenario.[2079]

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[2074] Eversource Initial Comments at 26-27.

[2075] NRECA Initial Comments at 48.

[2076] ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59-60; Energy Systems Integration Group June 2022 Report at 37).

[2077] *See* Dominion Initial Comments at 38.

[2078] New England for Offshore Wind Initial Comments at 2; *see also* Clean Energy Associations Initial Comments at 22 (arguing for selecting transmission facilities that maximize net benefits across multiple scenarios).

[2079] ACEG Initial Comments at 7, 30; ACORE Initial Comments at 14; Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 37-38.

945. A number of commenters recommend accounting for siting considerations in various ways in the selection of transmission facilities. For example, CARE Coalition recommends that the Commission require transmission providers to work with state authorities and other stakeholders to develop environmental- and energy justice-based siting criteria to guide transmission project selection and cost allocation.[2080] CARE Coalition also states that the Commission should allow RTOs/ISOs to take a flexible approach to identifying siting-based criteria that consider local and regional impacts, local and regional energy justice impacts (including use of existing transmission corridors and investment flow to disadvantaged communities as defined by the President's Justice40 Initiative), integration with plans for energy storage, and integration with major infrastructure development plans (e.g., highways, rail corridors).[2081] CARE Coalition states that planners and stakeholders should consider the economic, environmental, and other impacts associated with the full expected useful lives of proposed transmission and associated facilities.[2082]

946. Similarly, ACEG recommends selection criteria that account for whether potential transmission facilities use existing rights-of-way, contribute to equitable energy service, alleviate environmental justice concerns, or impact employment and economic

[2080] CARE Coalition Initial Comments at 7-8.

[2081] *Id.* at 10.

[2082] *Id.*

development.[2083] Exelon also recommends giving preference to approaches that prioritize existing rights-of-way, given that they are more readily accomplished and have fewer environmental impacts than greenfield transmission projects.[2084]

947. Acadia Center and CLF urge the Commission to provide transmission providers clear guidance, by adopting minimum selection criteria in the final rule, on their ability to consider factors such as environmental justice, mitigating environmental impacts, use of existing transmission facilities, and non-transmission alternatives, which have community and environmental benefits. Acadia Center and CLF contend that the consideration of these issues is consistent with NEPA, the FPA, and state law, and that, in the absence of such guidance, transmission providers may continue to exclude consideration of these issues given concerns regarding their authority and jurisdiction to do so.[2085] Grand Rapids NAACP also argues that the Commission has the authority to require that transmission providers explicitly incorporate energy equity and justice concerns into selection criteria, and that the Commission should do so in a final rule.[2086] WE ACT states that equity considerations and other non-energy benefits (e.g., pollution reduction, health, jobs, and local economic development) should be among the benefits that

[2083] ACEG Initial Comments at 59.

[2084] Exelon Initial Comments at 18.

[2085] Acadia Center and CLF Initial Comments at 11-12.

[2086] Grand Rapids NAACP Initial Comments at 17-23 (citations omitted).

transmission providers could use in selecting transmission facilities.[2087] PIOs assert that the Commission should require transmission providers to consider equity impacts when determining which transmission facilities to select, including whether construction of such facilities will impact environmental justice communities and what the cumulative impacts of the facilities will be.[2088]

948. DC and MD Offices of People's Counsel suggest that transmission providers should select transmission facilities that optimize the interconnection of portfolios of generation resources, including those that deliver benefits arising from grid decarbonization and the benefits set forth in the NOPR.[2089] Eversource argues that the Commission should consider requiring transmission providers to address needs identified in high-impact, low-frequency event scenarios, such that selection criteria would accommodate worst-case scenarios like Winter Storm Uri.[2090] Exelon urges that selection criteria be tied to well-established and defined needs, like reliability and market economics, such as reduced production costs, congestion, or capacity costs.[2091]

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[2087] WE ACT Initial Comments at 5.

[2088] PIOs Reply Comments at 17 (citations omitted).

[2089] DC and MD Offices of People's Counsel Initial Comments at 38-39.

[2090] Eversource Initial Comments at 26-27 (citing FERC, North American Electric Reliability Corporation, Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas, and the South-Central United States* (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and).

[2091] Exelon Initial Comments at 18.

949. Duke asserts that selection of a transmission facility in the absence of clear consensus from load-serving entities, states, and/or customers would be problematic and thwart the Commission's objectives, especially where certain transmission facilities will not be supported by state commissions in siting decisions or by consumer advocates in cost recovery proceedings.[2092] As such, Duke argues that the Commission should allow transmission providers to include a qualitative selection criterion of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of facilities.[2093] New York TOs state that New York Commission should retain its flexibility under NYISO's public policy transmission planning process such that, when the New York Commission identifies a transmission need driven by Public Policy Requirements, it can also require certain selection criteria in addition to those in NYISO's OATT.[2094]

950. NYISO contends that the final rule should continue to allow transmission providers to use a range of qualitative and quantitative criteria to rank and select transmission projects as the more efficient or cost-effective transmission facility.[2095] ACEG encourages the Commission to provide guidance in the final rule as to selection

[2092] Duke Initial Comments at 26-27.

[2093] *Id.* at 4, 26-27.

[2094] New York TOs Initial Comments at 9, 11-12, 15.

[2095] NYISO Initial Comments at 39-40.

criteria that meet its requirements, arguing that doing so would facilitate efficient compliance proceedings.[2096]

951. Maine Public Advocate also argues that the Commission should require transmission providers to select non-transmission alternatives when they meet an identified transmission need at the same or lower cost.[2097]

952. TAPS asserts that the Commission should require transmission providers to explain how their selection criteria would account for the uncertainty involved in predicting future transmission needs and to report "Affordability Metrics" that disclose the impact that selection of a particular transmission facility would have on transmission rates.[2098] TAPS argues that these "Affordability Metrics" would enhance the transparency of stakeholder processes in Long-Term Regional Transmission Planning and assist states in discussions about cost allocation and in considering whether to voluntarily fund a particular transmission facility or portfolio of transmission facilities.[2099]

953. ELCON states that, given the potential for massive transmission investment in the next 10 to 25 years, it is vitally important that consumers be protected from any

[2096] ACEG Initial Comments at 59.

[2097] Maine Public Advocate Initial Comments at 1-2.

[2098] TAPS Initial Comments at 16-17.

[2099] *Id.* at 19-20 (citing Alliant Energy, et al., ANOPR Initial Comments at 14; Alliant Energy, et al., ANOPR Reply Comments at 2-3).

unnecessary costs.[2100] As such, ELCON argues that selection criteria must incorporate metrics for reliability and economic efficiency, incorporate all potential drivers of transmission needs, and afford greater weight to those transmission facilities that produce benefits in more than one category.[2101]

### c. Commission Determination

#### i. Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities

954. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to propose evaluation processes, including selection criteria, that are transparent and not unduly discriminatory. Consistent with Order No. 1000,[2102] we adopt the NOPR proposal to establish a requirement that transmission providers' evaluation of transmission facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. As discussed further below, we modify the NOPR proposal to include a requirement that the determination of why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected must

[2100] ELCON Initial Comments at 16 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Net Zero America, 108 (Oct. 29, 2021), https://www.dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20%2829Oct2021%29.pdf?dl=0).

[2101] *Id.*

[2102] Order No. 1000, 136 FERC ¶ 61,051 at P 328.

include the measured benefits for each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) considered in the Long-Term Regional Transmission Planning process.

955. We also adopt the NOPR proposal, with modification, to require transmission providers to propose on compliance evaluation processes, including selection criteria, that aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs. We modify the NOPR proposal to provide additional clarity as to how transmission providers' evaluation processes must aim to ensure the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs by adopting several requirements. First, transmission providers in a transmission planning region must identify one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that address the Long-Term Transmission Needs that the transmission providers have identified through Long-Term Regional Transmission Planning. As part of this identification, consistent with Order Nos. 890 and 1000,[2103] nonincumbent transmission developers must be able to propose transmission facilities in Long-Term Regional Transmission Planning. Thus, we clarify that transmission providers in each transmission planning region must make clear in their OATTs the point in the Long-Term Regional Transmission Planning evaluation process at which they will accept Long-Term

[2103] *See id.* P 315 (citing Order No. 890, 118 FERC ¶ 61,119 at P 494; Order No. 890-A, 121 FERC ¶ 61,297 at PP 215-216).

Regional Transmission Facility proposals from stakeholders, including nonincumbent transmission developers. Second, transmission providers' evaluation processes must estimate the costs and measure the benefits of the Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are identified or proposed for potential selection, in addition to evaluating the identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities) using any qualitative or other quantitative selection criteria that the transmission providers in a transmission planning region propose to apply. Third, transmission providers must designate a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).[2104] This point must be no later than three years following the beginning of the Long-Term Regional Transmission Planning cycle.[2105] Finally, the evaluation process must culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. We reiterate, however, that, as discussed

[2104] As described further below in the Voluntary Funding Opportunities section, transmission providers must also provide Relevant State Entities with the opportunity to fund the cost of, or part of the cost of, the Long-Term Regional Transmission Facility (or portfolio of such Facilities) to ensure that it meets the transmission providers' selection criteria.

[2105] We note, however, consistent with the discussion above in the Frequency of Long-Term Scenario Revisions section, that transmission providers may evaluate and select additional Long-Term Regional Transmission Facilities during the period of the Long-Term Regional Transmission Planning cycle after this point and before the commencement of the next such cycle.

further below in the No Selection Requirement section, this final rule does not require transmission providers to select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) to address Long-Term Transmission Needs.

956. As discussed earlier, this final rule requires transmission providers to develop and use at least three Long-Term Scenarios, and one sensitivity analysis applied to each Long-Term Scenario, when conducting Long-Term Regional Transmission Planning. Each Long-Term Scenario or sensitivity analysis may suggest that different Long-Term Transmission Needs exist, that different Long-Term Regional Transmission Facilities would resolve those needs, or that such Long-Term Regional Transmission Facilities would provide different benefits for transmission customers. We clarify that, in the context of Long-Term Regional Transmission Planning, Order No. 890's requirements that transmission providers conduct coordinated, open, and transparent transmission planning on the regional level[2106] requires that transmission providers make transparent the methods that they used to analyze each individual Long-Term Scenario and the sensitivity or sensitivities applied to each scenario to determine the Long-Term Transmission Needs that exist in the transmission planning region, the Long-Term Regional Transmission Facilities that would resolve those needs, and the benefits of those Long-Term Regional Transmission Facilities for purposes of selection.[2107]

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[2106] Order No. 890, 118 FERC ¶ 61,119 at P 435.

[2107] For example, transmission providers might weigh specific Long-Term Scenarios and sensitivities based on the probability that the analyses reflect future system conditions (which the Commission referred to in the NOPR as a "weighted-benefits approach"). NOPR, 179 FERC ¶ 61,028 at P 251 (citing Brattle-Grid Strategies Oct.

957. Consistent with the Order No. 1000 regional transmission planning requirements,[2108] the Long-Term Regional Transmission Planning process must result in a regional transmission plan that identifies the Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet the transmission planning region's Long-Term Transmission Needs. To effectuate this requirement, we clarify that transmission providers have an affirmative obligation to identify Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, regardless of whether any stakeholder proposes potential Long-Term Regional Transmission Facilities for consideration in Long-Term Regional Transmission Planning. In this section, we enumerate specific requirements for how transmission providers conduct their Long-Term Regional Transmission Planning with the aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected. By clearly enumerating their evaluation processes and selection criteria in their OATTs, transmission providers will provide significant transparency to stakeholders to understand how Long-Term Transmission Needs will be addressed, whether there are more efficient or cost-effective Long-Term Regional Transmission Facilities that may meet those needs, and their benefits.

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2021 Report at 59-60).

[2108] Order No. 1000, 136 FERC ¶ 61,051 at PP 55, 146-148; *see Louisville Gas & Elec. Co.*, 144 FERC ¶ 61,054, at PP 61-62 (2013), *on reh'g sub nom.*, *Duke Energy Carolinas LLC*, 147 FERC ¶ 61,241, at PP 82-83 (2014).

958. Provided that transmission providers' evaluation processes and selection criteria comply with the requirements that we adopt here, we provide transmission providers with flexibility to determine how they will evaluate whether Long-Term Regional Transmission Facilities more efficiently or cost-effectively address Long-Term Transmission Needs, including by using benefit-cost ratios, assessing their net benefits and selecting the Long-Term Regional Transmission Facilities that maximize those benefits, and/or using some other method.[2109] Consistent with Order No. 1000 regional cost allocation principle (3), and as further discussed below in the Regional Transmission Cost Allocation section, transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[2110] We decline to reduce or increase the maximum benefit-cost ratio that transmission providers may use as a selection criterion in Long-Term Regional Transmission Planning. As the Commission found in Order No. 1000,[2111] requiring that a benefit-cost ratio, if adopted, not exceed

[2109] Nothing in this final rule requires the use of any particular approach, and we clarify that transmission providers may use more than one approach complementarily. *Compare, e.g.*, MISO Initial Comments at 54-56 (explaining MISO's approach to selecting transmission facilities with the goal of maximizing "long-term transmission value"), *with* MISO, FERC Electric Tariff, MISO OATT, attach. FF, Transmission Expansion Planning Protocol (90.0.0), §§ II.B.1.c, II.C.2.b (setting forth as a minimum selection criterion a benefit-cost ratio of 1.25 or 1.00 for Market Efficiency Projects and Multi-Value Projects, respectively).

[2110] NOPR, 179 FERC ¶ 61,028 at P 243 n.390; Order No. 1000, 136 FERC ¶ 61,051 at P 646.

[2111] Order No. 1000, 136 FERC ¶ 61,051 at P 648.

1.25-to-1.00 ensures that the ratio is not so high as to exclude Long-Term Regional Transmission Facilities with significant positive net benefits from selection.

959. We decline to require transmission providers to account for siting considerations in their evaluation process and selection criteria.[2112] We acknowledge that siting considerations (e.g., use of existing rights-of-way) may affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility. While such siting considerations may inform the evaluation process and selection criteria, we do not require transmission providers to account for such considerations in this final rule. We note, however, that, as discussed below in the Role of Relevant State Entities section, this final rule requires that transmission providers consult with and seek the support of Relevant State Entities[2113] regarding the evaluation process and selection criteria that transmission providers propose to use to evaluate Long-Term Regional Transmission Facilities for selection.

960. We also do not require transmission providers to include environmental justice or equity considerations in their evaluation process or selection criteria. While several commenters recommend that we impose such requirements,[2114] none provides any

[2112] CARE Coalition Initial Comments at 7-8; *see also* ACEG Initial Comments at 59; Exelon Initial Comments at 18.

[2113] Many Relevant State Entities exercise their state's authority over the siting of transmission facilities.

[2114] *See, e.g.*, Acadia Center and CLF Initial Comments at 11-12; Grand Rapids NAACP Initial Comments at 17-23 (citations omitted); PIOs Reply Comments at 17 (citations omitted).

approach for how these concerns would be incorporated into transmission providers' evaluation process and selection criteria on a generic basis. We acknowledge that the selection of Long-Term Regional Transmission Facilities represents a substantial step in the development of new electric transmission infrastructure, which may impact environmental justice communities or raise equity concerns. We further recognize that such environmental justice or equity considerations may affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility, particularly in regions where legal frameworks provide for consideration of environmental justice and equity. Nothing in this final rule precludes transmission providers from proposing on compliance to include environmental justice considerations within their evaluation process and selection criteria.

961. NYISO requests that the Commission clarify that transmission providers may continue to use qualitative and quantitative measures in the Long-Term Regional Transmission Planning process.[2115] We clarify that nothing in this final rule prohibits transmission providers from proposing to use qualitative factors in their evaluation processes and/or selection criteria. Accordingly, transmission providers may propose to use qualitative factors in their evaluation processes and/or qualitative selection criteria, provided that they demonstrate on compliance that their proposals comply with the evaluation process and selection criteria requirements of this final rule.

[2115] NYISO Initial Comments at 39-40.

962. In response to Duke's request to allow transmission providers to include a selection criterion that is a qualitative evaluation of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of such Facilities,[2116] we find that transmission providers may not include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Rather than address this issue via selection criteria regarding a *transmission provider's* anticipation of such an entity's response, we conclude that the requirement discussed below to consult with and seek support from Relevant State Entities regarding the evaluation process and selection criteria is a more appropriate mechanism to account for the Relevant State Entity's views. We also note that beyond this consultative process, state public utility commissions and consumer advocates have numerous opportunities to express their views on transmission development, including through state- and Commission-jurisdictional proceedings. Further, allowing such features in evaluation processes or selection criteria could amount to a requirement that transmission providers obtain the consent of Relevant State Entities, which, as discussed below in the Role of Relevant State Entities section, we do not believe is necessary or appropriate to resolve the deficiencies identified in this final rule.[2117]

[2116] Duke Initial Comments at 4, 26-27.

[2117] *See New York v. FERC*, 535 U.S.at 26-28 (upholding Commission's decision

963. In response to New York TOs,[2118] we decline to require that transmission providers include selection criteria requested by state public utility commissions. As discussed further below in the Role of Relevant State Entities section, transmission providers must propose on compliance an evaluation process and selection criteria that comply with the requirements of this final rule after consulting with and seeking the support of Relevant State Entities. To the extent that a transmission provider believes that a selection criterion proposed by a Relevant State Entity would comply with the final rule requirements, they may propose to include that criterion in their compliance filings, and the Commission will determine if it complies with these requirements.

### ii. Maximize Benefits

964. We adopt the NOPR proposal, with modification, to require that transmission providers in each transmission planning region propose evaluation processes, including selection criteria, that seek to maximize benefits accounting for costs over time without over-building transmission facilities. In the NOPR, the Commission proposed that the evaluation processes and selection criteria seek to maximize benefits to consumers over time without over-building transmission facilities. However, we believe that it is appropriate to modify that proposal for clarity. We modify the requirement to require that transmission providers' evaluation processes and selection criteria seek to maximize benefits *accounting for costs*. Some commenters have interpreted the NOPR as

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not to assert jurisdiction over bundled retail transmission).

[2118] New York TOs Initial Comments at 9, 11-12, 15.

proposing to allow transmission providers to disregard costs and simply maximize benefits.[2119] We clarify that was not the Commission's intent, and we modify the NOPR proposal in this final rule to make that clear. Further, we note that while we omit reference "to consumers" in the requirement for brevity, we do not view this change as substantive. As discussed above, this requirement, together with other aspects of this final rule, helps to ensure transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs in order to ensure just and reasonable Commission-jurisdictional rates, which ultimately benefits ratepayers.

965. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section, transmission providers conducting Long-Term Regional Transmission Planning must use and measure a set of benefits to evaluate Long-Term Regional Transmission Facilities. In setting forth an evaluation process and selection criteria, we clarify, consistent with the directive to seek to maximize benefits accounting for costs over time without over-building transmission facilities, that transmission providers may not disregard benefits that we require them to use and measure when implementing their approved evaluation process and selection criteria.[2120] We further clarify that transmission providers may not disregard benefits even where those benefits

[2119] *See, e.g.*, Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at P 242); Vistra Initial Comments at 17-18; WATT Coalition Initial Comments at 9.

are only measured in certain transmission system conditions, such as may be the case with Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, and therefore are captured only under certain Long-Term Scenarios or sensitivities thereto. While transmission providers may not disregard such benefits, transmission providers' evaluation processes and selection criteria may account for the fact that certain benefits are only measured under certain conditions by, for example, weighting how likely certain conditions expressed in specific Long-Term Scenarios or sensitivities are to occur.

966. As discussed further below, transmission providers have the discretion to select or not select any Long-Term Regional Transmission Facility that they identify through Long-Term Regional Transmission Planning, even a facility that otherwise meets the selection criteria. However, as noted above, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected to address Long-Term Transmission Needs. We clarify that this determination must include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) evaluated by the transmission providers, whether or not the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[2121]

[2121] Where transmission providers employ a portfolio approach to evaluating and selecting Long-Term Regional Transmission Facilities, we require only that they include in such a determination the measured benefits for the portfolio of Long-Term Regional

967. We acknowledge commenters' concerns that there is inherent uncertainty in Long-Term Regional Transmission Planning.[2122] This final rule adopts provisions that allow for significant flexibility for transmission providers to address that uncertainty. As stated above in the Participation in Long-Term Regional Transmission Planning section, we require transmission providers to develop and use Long-Term Scenarios, which are a critical tool for managing uncertainty and facilitating regional transmission planning that account for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, transmission providers could adopt evaluation processes and selection criteria that would allow transmission providers to make selection decisions while minimizing the future risk of developing a previously selected Long-Term Regional Transmission Facility that is not the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. For example, transmission providers might develop a least-regrets approach under which they would select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation if those Long-Term Regional Transmission Facilities are net beneficial in more than one Long-Term Scenario and sensitivity analyses even if other transmission facilities have a higher benefit-cost ratio or provide more net benefits in a single Long-Term Scenario or particular sensitivity. Transmission providers might also

Transmission Facilities on an aggregate basis.

[2122] *See, e.g.*, GridLab Initial Comments at 19; TAPS Initial Comments at 16-17.

adopt a weighted-benefits approach under which they would select a Long-Term Regional Transmission Facility based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario or sensitivity thereof that is studied. Under either approach, to maximize benefits accounting for costs over time without over-building transmission facilities, transmission providers must consider not only the risk that changing conditions might produce fewer benefits than originally anticipated, but also that they might produce *more* benefits than originally anticipated. Finally, as discussed below in the Reevaluation section, we require transmission providers to reevaluate certain selected Long-Term Regional Transmission Facilities to determine whether they continue to meet the transmission providers' selection criteria.

968. While we acknowledge commenters' wide support for least-regrets and weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities in Long-Term Regional Transmission Planning, we decline to require transmission providers to use either approach. However, we clarify that transmission providers may not adopt an approach under which they would not select a Long-Term Regional Transmission Facility unless it meets their selection criteria in every Long-Term Scenario and sensitivity. We are concerned that such an approach could impose a threshold for selection that is so onerous it limits selection of most or all Long-Term Regional Transmission Facilities, and, as such, is inconsistent with the requirement that selection criteria seek to maximize benefits accounting for costs over time without over-building transmission facilities. We find that such an approach would not ensure that transmission providers have the opportunity to select Long-Term Regional Transmission Facilities to

more efficiently or cost-effectively address Long-Term Transmission Needs, an opportunity that we find, as described in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section above, is necessary to ensure just and reasonable Commission-jurisdictional rates.

969. Again, we emphasize that this final rule does not require that transmission providers select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities). Rather, this final rule simply requires transmission providers to adopt an evaluation process and selection criteria that meet the minimum requirements set forth in this final rule, including that they aim to maximize benefits accounting for costs over time without over-building transmission facilities. In response to NYISO,[2123] however, we decline to clarify the definition of "over-building," because doing so would limit transmission providers' flexibility to assess what constitutes over-building in their transmission planning region. Transmission planning regions have a wide variety of market structures, and numerous factors drive transmission needs, which may require evaluation processes and selection criteria that maximize benefits accounting for costs or guard against over-building in different ways. We expect that evaluation processes and selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities will include a variety of features, based on their regional circumstances, that combine to ensure that transmission providers give careful, informed consideration to Long-Term Regional Transmission Facilities that more efficiently or

[2123] NYISO Initial Comments at 43.

cost-effectively address Long-Term Transmission Needs. We also note that, in response to CTC Global's concerns about the selection criteria being limited to considering regional transmission facilities with the least capital costs,[2124] we clarify that both estimated benefits and costs must be disclosed when evaluating a Long-Term Regional Transmission Facility for selection and that transmission providers must adopt selection criteria that seek to maximize benefits accounting for costs over time without over-building transmission facilities.

970. In response to Maine Public Advocate,[2125] we decline to require transmission providers to select non-transmission alternatives where such non-transmission alternatives meet a Long-Term Transmission Need at a lower cost than an alternative Long-Term Regional Transmission Facility. The Commission did not propose to require transmission providers to consider non-transmission alternatives for potential selection in the NOPR, and we are not persuaded to do so in this final rule. We note, however, that transmission providers already are required to consider non-transmission alternatives on a comparable basis in regional transmission planning.[2126]

971. Finally, in response to TAPS,[2127] we decline to require transmission providers to develop affordability metrics to provide along with other information about a particular

[2124] CTC Global Initial Comments at 9.

[2125] Maine Public Advocate Initial Comments at 1-2.

[2126] Order No. 1000, 136 FERC ¶ 61,051 at P 148.

[2127] TAPS Initial Comments at 16-17, 19-20 (citations omitted).

Long-Term Regional Transmission Facility. The Commission did not propose such a requirement in the NOPR, and we are not persuaded to adopt a requirement for such metrics in this final rule.

#### 4. Role of Relevant State Entities

##### a. NOPR Proposal

972. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a process to coordinate with the Relevant State Entities in developing selection criteria.[2128] Regarding this requirement, the Commission proposed to require transmission providers to demonstrate on compliance that they consulted with and sought support from the Relevant State Entities in their transmission planning region's footprint to develop their proposed selection criteria.[2129]

##### b. Comments

###### i. Support/Oppose

973. Many commenters support the Commission's proposal to require transmission providers to consult with and seek support from Relevant State Entities[2130] and include in

[2128] NOPR, 179 FERC ¶ 61,028 at P 241.

[2129] *Id.* P 246.

[2130] *See* ACEG Initial Comments at 59-60; Ameren Initial Comments at 20; American Municipal Power Initial Comments at 12; California Commission Initial Comments at 37; ELCON Initial Comments at 17; Nebraska Commission Initial Comments at 8-9; North Carolina Commission and Staff Initial Comments at 4-5; Pennsylvania Commission Initial Comments at 10; PJM States Initial Comments at 3.

their OATTs a process to coordinate with the Relevant State Entities[2131] in developing selection criteria. For example, ELCON argues that coordination with Relevant State Entities in identifying selection criteria is critical because it will promote cooperation and could result in more efficient state siting and permitting processes.[2132] Pennsylvania Commission asserts that requiring consultation will provide states the opportunity to influence regional transmission planning and cost allocation, thereby promoting the public interest and reducing conflicts and disputes on these matters.[2133]

974. ISO-NE supports the proposal to provide states with a greater role in the selection of transmission facilities.[2134] Further, ISO-NE argues that, in the context of policy-based planning, states should be responsible for determining whether to select transmission facilities, with ISO-NE playing a supporting, technical role.[2135] While NESCOE supports the proposal that transmission providers must consult with and seek support from Relevant State Entities within their transmission planning region's footprint to develop selection criteria, NESCOE requests that the Commission provide Relevant State Entities

[2131] *See* NARUC Initial Comments at 44; NESCOE Initial Comments at 9-10, 46; Pacific Northwest State Agencies Initial Comments at 19; PJM States Initial Comments at 3.

[2132] ELCON Initial Comments at 17.

[2133] Pennsylvania Commission Initial Comments at 10.

[2134] ISO-NE Initial Comments at 35.

[2135] *Id.* NESCOE supports ISO-NE's position. NESCOE Reply Comments at 5 & n.16.

an expanded role in the selection of transmission projects where the project is identified as needed in response to state laws or policy goals and require transmission providers to include such a role in their OATTs.[2136]

975. PJM states that it also supports providing additional opportunity for involvement by states and stakeholders in Long-Term Regional Transmission Planning; however, in response to ISO-NE, PJM urges the Commission to make clear that transmission providers retain authority to select transmission facilities and argues that such role is more than a "technical supporting role."[2137] PJM States contend that an upfront and transparent process, with substantive state involvement, will ensure that selection criteria are thoroughly discussed by stakeholders and are consistent with the rest of Long-Term Regional Transmission Planning.[2138]

976. New York Commission and NYSERDA state that the Commission should allow Relevant State Entities to be part of the decision-making process regarding the appropriate timeframe for selecting a transmission facility.[2139]

977. California Commission urges the Commission to require that transmission providers indicate in their compliance filings whether the selection criteria they propose are supported by the Relevant State Entities and, if not, to explain any points of

[2136] NESCOE Initial Comments at 9-10, 48-49.

[2137] PJM Reply Comments at 35-36 (citing ISO-NE Initial Comments at 16).

[2138] PJM States Reply Comments at 8.

[2139] New York Commission and NYSERDA Initial Comments at 12.

disagreement.[2140] PJM States argue that the Commission should, without dictating any substantive outcomes, "recognize the primacy of the role for retail regulators" in the final rule.[2141] By contrast, ACEG cautions that transmission providers must balance all states' interests when developing selection criteria instead of maximizing one state's interest over another's.[2142] NYISO states that each transmission planning region should have flexibility to determine how it will consult with and seek support from Relevant State Entities regarding selection criteria.[2143]

978. To ensure that consultation is successful, NARUC recommends that the Commission require transmission providers to take two steps: (1) communicate with the Relevant State Entities promptly following issuance of a final rule in a manner that is reasonably calculated to be received by the Relevant State Entities; and (2) establish a forum for negotiation that enables full and robust participation by both transmission providers and Relevant State Entities during the period allotted for making compliance filings.[2144]

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[2140] California Commission Initial Comments at 37-38.

[2141] PJM States Initial Comments at 3-4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

[2142] ACEG Initial Comments at 59-60.

[2143] NYISO Initial Comments at 44.

[2144] NARUC Initial Comments at 44.

979. Some commenters oppose the Commission's NOPR proposal.[2145] Dominion argues that mandating involvement by Relevant State Entities would unnecessarily burden transmission providers.[2146] Louisiana Commission argues that the proposal would represent "superficial state involvement" and serve as "window dressing" for the erosion of state authority due to Long-Term Regional Transmission Planning. Louisiana Commission argues that collective oversight by the states within an RTO/ISO is not equivalent to state oversight of its own retail electric service companies, particularly in circumstances where states are subject to the decisions of the majority.[2147]

980. APPA opposes any requirement for transmission providers to consult with, and/or seek the support of, Relevant State Entities in identifying selection criteria.[2148] APPA contends that Relevant State Entities should be considered in the same manner as other stakeholders under the requirements of Order Nos. 890 and 1000.[2149] DC and MD Offices of People's Counsel disagree with APPA, arguing that the Commission should afford Relevant State Entities an expansive role in the selection of transmission facilities

[2145] *See, e.g.*, Clean Energy Associations Initial Comments at 22-23 (arguing that, while state involvement should play a role, the Commission should set forth *pro forma* selection criteria).

[2146] Dominion Initial Comments at 37-38.

[2147] Louisiana Commission Initial Comments at 27.

[2148] APPA Initial Comments at 34.

[2149] *Id.*

in Long-Term Regional Transmission Planning.[2150] DC and MD Offices of People's Counsel contend that Relevant State Entities can reach agreement quickly and have access to the best available data used for baseline planning and scenario analysis of transmission facilities.[2151]

981. MISO takes no position but argues that its existing processes already entail extensive stakeholder engagement, including consulting with state regulatory commissions individually and through OMS, to determine the selection criteria that should be used to maximize long-term transmission value and to ensure an adequate, reliable, and resilient transmission system.[2152]

### ii. Obtaining/Not Obtaining Consent

982. Several commenters discuss whether transmission providers need only consult with and seek support from Relevant State Entities in the development of selection criteria, or whether they also must obtain their consent.[2153] For example, Indicated PJM TOs support the NOPR proposal but argue that the Commission should not require transmission providers to obtain the agreement of Relevant State Entities in determining

[2150] DC and MD Offices of People's Counsel Reply Comments at 9 (citing APPA Initial Comments at 35).

[2151] *Id.*

[2152] MISO Initial Comments at 55.

[2153] *See, e.g.*, Acadia Center and CLF Initial Comments at 27-28 (arguing that states should have veto authority over transmission providers' selection criteria in certain circumstances).

selection criteria.[2154] AEP agrees and argues that state input should be only one factor and that engineering considerations should drive the establishment of selection criteria. AEP also expresses skepticism that requiring transmission providers to consult with Relevant State Entities will increase the chances that states will site the transmission facilities that transmission providers select, because transmission line siting processes will occur years after the establishment of selection criteria, will likely be performed by different personnel, and will address considerations separate from those in establishing selection criteria.[2155]

983. Southeast PIOs argue that, while they do not oppose factoring state and consumer support into the selection of transmission facilities, the Commission should not require transmission providers to obtain the approval of Relevant State Entities prior to selection of transmission facilities, because doing so would risk indefinitely delaying Long-Term Regional Transmission Planning.[2156]

984. PJM argues that it should be able to develop selection criteria in the event that Relevant State Entities do not agree on the establishment of selection criteria. PJM recommends that the Commission clarify that any requirement to demonstrate that transmission providers have consulted with and sought support from Relevant State

[2154] Indicated PJM TOs Initial Comments at 18 (citing NOPR 179, FERC ¶61,028 at PP 244, 246).

[2155] AEP Initial Comments at 29-30.

[2156] Southeast PIOs Reply Comments at 27.

Entities could be satisfied even if the transmission provider is unable to secure the agreement of Relevant State Entities.[2157]

985. By contrast, NARUC opposes a process in which transmission providers consult with and seek support from Relevant State Entities but are empowered to override or ignore selection criteria proposed and supported by Relevant State Entities. NARUC seeks clarification as to what recourse will be available to Relevant State Entities in the event that there is not agreement on selection criteria.[2158] Nebraska Commission argues that the Commission should require transmission providers to demonstrate to the greatest extent possible that they gained the support of Relevant State Entities, because otherwise the process of consulting with and seeking support from Relevant State Entities could become a mere exercise.[2159]

986. Mississippi Commission suggests that the Commission require transmission providers to obtain the agreement of Relevant State Entities on selection criteria for Long-Term Regional Transmission Planning.[2160] Southern goes further, arguing that the Commission should allow Relevant State Entities to use the State Agreement Process not only to allocate the costs of Long-Term Regional Transmission Facilities, but also to

[2157] PJM Initial Comments at 104.

[2158] NARUC Initial Comments at 45.

[2159] Nebraska Commission Initial Comments at 8-9.

[2160] Mississippi Commission Initial Comments at 3-4 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 11)).

select such transmission facilities in the first instance. Southern contends that, if the Commission does not allow states to select transmission facilities, the Commission will unlawfully intrude into state jurisdiction over resource planning.[2161]

987. Acadia Center and CLF assert that states should have the authority to propose selection criteria, arguing that this will ensure that transmission providers do not refuse to consider states' interests and goals regarding transmission needs. Acadia Center and CLF further contend that states should have veto authority over transmission providers' selection criteria in certain scenarios, such as ISO-NE, where a majority of states in a transmission planning region have decarbonization goals but the ISO/RTO continues to apply business-as-usual selection criteria that prioritize reliability and economic considerations.[2162]

988. AEE argues that the final rule should clearly provide an opportunity for states to suggest selection criteria and inputs for analyzing transmission projects, noting that such a process may need to be continually developed following issuance of a final rule.[2163]

### iii. Consultation with Other Entities

989. A number of commenters argue that transmission providers should consult with and seek support from other entities in addition to Relevant State Entities. Large Public Power does not object to the NOPR proposal but argues that it is essential that municipal

[2161] Southern Initial Comments at 6-10 & n.12 (citations omitted).

[2162] Acadia Center and CLF Initial Comments at 27-28.

[2163] AEE Initial Comments at 30-32 (citations omitted).

utilities also be included as participants in the consultative process.[2164] American Municipal Power urges the Commission to recognize that publicly-owned utilities play a role analogous to state commissions, in that they are publicly accountable, operate through open and transparent procedures, and adopt policies reflecting the consensus of communities that own and support them. American Municipal Power argues that FPA section 217(b)(4) requires the Commission to revise the NOPR proposal such that load-serving entities, including publicly-owned utilities, are on a par with Relevant State Entities.[2165] NRECA agrees, arguing that Relevant State Entities may not have regulatory authority over electric cooperatives, and therefore the Commission must modify its proposal to include consultation with load-serving entities to conform with FPA section 217(b)(4) and Order No. 1000's transmission planning principles.[2166]

990. Relatedly, NARUC argues that nothing in the final rule should inhibit states from permitting the participation of certain quasi-public/private state and federal entities or other state entities in addition to Relevant State Entities.[2167] NEPOOL states that the selection of any transmission facilities should be made with substantial input from both market participant stakeholders and the transmission planning region's states.[2168]

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[2164] Large Public Power Initial Comments at 30.

[2165] American Municipal Power Initial Comments at 12-13.

[2166] NRECA Initial Comments at 50.

[2167] NARUC Initial Comments at 29-30 (citation omitted).

[2168] NEPOOL Initial Comments at 8.

### iv. Practical Implementation Issues

991. Several commenters discuss practical issues with the requirement that transmission providers consult with and seek the support of Relevant State Entities in developing selection criteria. For example, PPL generally supports the Commission's proposal but contends that some states may find it difficult to fulfill the role described in the NOPR. PPL therefore argues that the Commission should allow transmission providers flexibility in developing consultative processes.[2169] AEP argues that some states will be unable to participate effectively given a lack of resources or statutory limitations, such that the consultative process may result in selection criteria "that unfairly or unreasonably emphasize certain values."[2170] NESCOE states that the Commission should provide flexibility as to how states elect to engage in the transmission planning process, noting that a state official's role in siting electric infrastructure may make it preferable for a different state official to provide that state's view on certain aspects of Long-Term Regional Transmission Planning, such as transmission project selection.[2171]

[2169] PPL Initial Comments at 18-19.

[2170] AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290).

[2171] NESCOE Initial Comments at 9 n.16.

992. NEPOOL requests that the Commission articulate principles for who should make selection decisions when a Long-Term Regional Transmission Facility may address transmission needs driven by reliability, economics, and public policy.[2172]

993. Michigan State Entities argue that the success of the Commission's proposed reforms depends on transmission providers meaningfully engaging with stakeholders, which requires that stakeholders have the time and capability to participate in a stakeholder review process. Michigan State Entities further assert that stakeholders representing diffuse and broad interests (e.g., residential ratepayers), as opposed to concentrated interests, tend to have fewer resources with which to fund participation in these processes, noting that many states have created consumer advocacy agencies to correct this imbalance. Michigan State Entities assert that the Commission should require that transmission providers include RTO/ISO-level, publicly funded consumer advocates in the stakeholder processes that are empowered to participate in approving selection criteria.[2173]

### c. Commission Determination

994. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consult with and seek support from Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional

[2172] NEPOOL Initial Comments at 8.

[2173] Michigan State Entities Initial Comments at 4-5.

Transmission Facilities for selection. Specifically, we require transmission providers to demonstrate on compliance that they made good faith efforts to consult with and seek support from Relevant State Entities in their transmission planning region's footprint when developing the evaluation process and selection criteria that they propose to include in their OATTs.[2174]

995. We decline to adopt the NOPR proposal to require transmission providers to include in their OATTs a process for coordinating with Relevant State Entities. We believe that the requirement adopted in this final rule will simplify compliance efforts without sacrificing the benefits of consulting with and seeking the support of Relevant State Entities. We disagree with Dominion that requiring transmission providers to consult with and seek support from Relevant State Entities will prove burdensome, and we believe that our decision not to require transmission providers to include a process for such consultation in their OATTs will further reduce any administrative burden of this requirement.[2175]

996. We clarify that we require transmission providers to seek support from Relevant State Entities, but do not require transmission providers to obtain their support, before proposing an evaluation process and selection criteria on compliance.[2176] In response to

[2174] In response to New York Commission and NYSERDA, we note that such consultation may include discussion of the appropriate timeframe for selecting a Long-Term Regional Transmission Facility. New York Commission and NYSERDA Initial Comments at 12.

[2175] *See* Dominion Initial Comments at 37-38.

[2176] *See, e.g.*, PJM Initial Comments at 104 (requesting clarification that

Acadia Center and CLF, we note that Relevant State Entities may propose selection criteria to transmission providers, but ultimately, it is transmission providers who must propose on compliance an evaluation process and selection criteria that comply with the requirements of this final rule. We further note that providing states with veto authority over transmission providers' proposed selection criteria would be akin to requiring transmission providers to obtain the support of Relevant State Entities, and therefore we do not adopt Acadia Center and CLF's recommendation.[2177] While we believe that Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation process and selection criteria, we reiterate that transmission planning is the tariff obligation of each transmission provider and transmission providers retain ultimate responsibility for regional transmission planning, including Long-Term Regional Transmission Planning, as well as complying with the obligations of this final rule.[2178] Moreover, we acknowledge that achieving consensus may not be possible in every instance.

transmission providers are permitted to submit an evaluation process and selection criteria on compliance in the absence of obtaining the support of Relevant State Entities).

[2177] *See* Acadia Center and CLF Initial Comments at 27-28.

[2178] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 153 ("[T]he ultimate responsibility for transmission planning remains with public utility transmission providers." (citing Order No. 890, 118 FERC ¶ 61,119 at P 454)).

997. We disagree with NARUC that, in the absence of a requirement that transmission providers obtain the support of Relevant State Entities, transmission providers will be empowered to ignore the input of Relevant State Entities. In this final rule, we require transmission providers to make good faith efforts to consult with and seek the support of Relevant State Entities. We do not agree that the failure to obtain the support of Relevant State Entities is necessarily evidence that transmission providers did not exercise good faith efforts to seek their support.

998. For similar reasons, we also disagree with Louisiana Commission when it argues that requiring transmission providers to simply consult with and seek support from Relevant State Entities will amount to only superficial state involvement in the development of an evaluation process and selection criteria.[2179] In response to Louisiana Commission's additional contention that collective oversight of regional transmission planning processes by the transmission planning region's states is not equivalent to state oversight of its own retail electric service companies, we reiterate that this final rule requires transmission providers to engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs in order to ensure *Commission-jurisdictional* rates are just and reasonable. As discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, the final rule neither aims at nor conflicts with state authority over retail rates.

[2179] Louisiana Commission Initial Comments at 27.

999. We do not believe that it is necessary to adopt California Commission's proposal to require transmission providers to indicate in their compliance filings whether Relevant State Entities support the proposal or explain any points of disagreement that they may have with Relevant State Entities. Relevant State Entities may intervene in compliance filing proceedings and provide this information for the Commission's consideration as it determines whether transmission providers have met the requirements that we adopt in this final rule. Nor do we adopt NARUC's request that we impose specific requirements dictating how transmission providers should consult with and seek the support of Relevant State Entities beyond the requirement that they demonstrate good faith efforts to do so. We believe that it is appropriate to provide transmission providers with flexibility in how to consult with and seek support of Relevant State Entities based on the specific needs and makeup of their transmission planning region. Further, we acknowledge, as argued by some commenters,[2180] that practical or legal limitations may limit the extent to which some Relevant State Entities may participate in such processes, reinforcing the need for flexibility.

1000. We clarify that nothing in this final rule diminishes the role of stakeholders that are not Relevant State Entities, nor absolves transmission providers of any existing obligations that they may have to provide opportunities for stakeholder input.[2181] That

[2180] *See* AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290); NESCOE Initial Comments at 9 n.16; PPL Initial Comments at 18-19.

[2181] In response to NARUC and NEPOOL, *see* NARUC Initial Comments at 29-30; NEPOOL Initial Comments at 9, we reiterate that this may include other state entities in addition to Relevant State Entities, such as federal entities, market participants, and

said, we decline to require transmission providers to consult with or seek support from entities in addition to Relevant State Entities, including load-serving entities.[2182] This final rule recognizes that Relevant State Entities play a unique role in representing the interests of states, which retain a variety of authorities, including those under FPA section 201, that are integral to the success of Long-Term Regional Transmission Planning.

1001. Further, we disagree with American Municipal Power that FPA section 217(b)(4) requires that this final rule treat load-serving entities on par with Relevant State Entities. Through the requirements of this final rule, we seek to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations and facilitate the planning of a reliable grid, consistent with FPA section 217(b)(4). Nothing in our determination to require transmission providers to consult with and seek support from Relevant State Entities (but not load-serving entities) changes that aim or undercuts the ability of Long-Term Regional Transmission Planning to achieve it. We continue to find that other requirements in the final rule, including the requirement to incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities in the development of Long-Term Scenarios, ensure load-serving entities'

other stakeholders.

[2182] *See, e.g.*, American Municipal Power Initial Comments at 12-13; Large Public Power Initial Comments at 30.

reasonable needs for transmission capacity to meet their service obligations are incorporated into Long-Term Regional Transmission Planning.

1002. Finally, in response to commenters,[2183] we clarify that transmission providers, not Relevant State Entities, must determine whether or not to select Long-Term Transmission Facilities to meet Long-Term Transmission Needs. Under the FPA, the Commission has jurisdiction over transmission providers, and those entities, not Relevant State Entities, are subject to the requirements of this final rule. As discussed above in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section, we require herein that transmission providers designate a point in the evaluation process at which they will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).

### 5. Voluntary Funding Opportunities

#### a. NOPR Proposal

1003. In the NOPR, the Commission sought comment on whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility to enable such facility to meet transmission

[2183] *See, e.g.*, ISO-NE Initial Comments at 35 (arguing that states should be responsible for determining whether to select transmission facilities and that transmission providers should play a supportive, technical role); NEPOOL Initial Comments at 8 (requesting that the Commission articulate principles for who should select multi-value transmission facilities); NESCOE Initial Comments at 9,48-49 (requesting that the Commission require transmission providers to include a role in their OATTs for Relevant State Entities in the selection of Long-Term Regional Transmission Facilities); PJM Reply Comments at 36 (requesting that the Commission clarify that transmission providers retain the authority to select transmission facilities).

providers' selection criteria (e.g., any benefit-cost threshold), and if so, what mechanism would be appropriate to document such voluntary funding agreements, how transmission providers would be assured that commitments to provide funding would be sufficiently binding, and what the most appropriate point would be in the process for such voluntary commitments.[2184] The Commission also sought comment on whether such a voluntary funding opportunity should be extended to other entities, such as interconnection customers.[2185]

**b. Comments**

1004. Of commenters that address the question posed in the NOPR regarding whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility, nearly all argue that the Commission should allow such an opportunity.[2186] ISO-NE argues that the

[2184] NOPR, 179 FERC ¶ 61,028 at P 252. The Commission stated that, for Long-Term Regional Transmission Facilities, such an opportunity for the Relevant State Entities could enable them to assign a value to achieving their particular policy goals while ensuring that their customers bear the corresponding costs. *Id.* P 252 n.399.

[2185] *Id.*

[2186] *See* Ameren Initial Comments at 21; APPA Initial Comments at 34-35; Clean Energy Associations Initial Comments at 23; Duke Initial Comments at 28-29; Grid United Initial Comments at 6; Idaho Commission Initial Comments at 5; ISO-NE Initial Comments at 36; Louisiana Commission Initial Comments at 29; NARUC Initial Comments at 31-32 (citing *MISO-SPP Joint Targeted Interconnection Queue Study (JTIQ)*, MISO, https://www.misoenergy.org/engage/committees/miso-spp-joint-targeted-interconnection-queue-study/); New Jersey Commission Initial Comments at 25; PPL Initial Comments at 19; SDG&E Initial Comments at 4; WATT Coalition Initial Comments at 11; Xcel Initial Comments at 14 (stating that neither the FPA nor the Commission's rules and regulations categorically preclude voluntary agreement to plan and pay for new transmission facilities (citing Order No. 1000, 136 FERC ¶ 61,051 at

Commission should provide flexibility to transmission providers to determine the specific means for documenting the state's agreement to provide such funding.[2187] APPA argues that the Commission should require the filing under FPA section 205 of agreements to fund the cost of, or a portion of the cost of, a transmission facility so that affected parties have an opportunity to comment.[2188]

1005. Grid United argues that, while it supports *ex ante* cost allocation methods, the Commission also should continue to permit alternative cost recovery arrangements, including participant funding agreements and voluntary agreements entered into by generation developers and Relevant State Entities.[2189] Duke asserts that the Commission should avoid prescriptive rules that discourage or undervalue voluntary funding from transmission providers, states, Relevant State Entities, or interconnection customers.[2190] Xcel argues that the Commission should state in a final rule that neither the FPA nor the Commission's rules and regulations forbid voluntary arrangements for planning and paying for transmission facilities.[2191]

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PP 146, 561, 724; *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3)).

[2187] ISO-NE Initial Comments at 36.

[2188] APPA Initial Comments at 34-35 (citing *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024 (2022)).

[2189] Grid United Initial Comments at 6.

[2190] Duke Initial Comments at 28-29.

[2191] Xcel Initial Comments at 14.

1006. NARUC argues that the final rule should not inhibit the flexibility of Relevant State Entities in developing approaches to such voluntary funding commitments.[2192] NARUC argues that the final rule should be as flexible as possible in providing voluntary funding opportunities to account for the variety of state laws enabling such authority and to allow for the possibility of sharing the costs of such transmission facilities between load and generator developers.[2193]

1007. Louisiana Commission supports the NOPR proposal and argues that voluntary agreement is the only fair, reasonable, and just way to allocate the costs of transmission facilities selected in Long-Term Regional Transmission Planning.[2194] Ameren believes that Relevant State Entities should have the opportunity to fund a portion of the cost of a transmission facility that otherwise would not meet the OATT selection criteria but requests that the Commission clarify that this decision "is referring to cost allocation."[2195] Ameren argues that without this clarification, Relevant State Entities could fund part of the transmission facility while imposing on a transmission owner the obligation to operate and maintain that facility and assure regulatory compliance without adequate

[2192] NARUC Initial Comments at 31-32; *accord* Idaho Commission Initial Comments at 5.

[2193] NARUC Initial Comments at 32.

[2194] Louisiana Commission Initial Comments at 29.

[2195] Ameren Initial Comments at 21-22 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

compensation, in violation of the D.C. Circuit's determination in *Ameren Services Co. v. FERC* that transmission owners "should not be forced to operate as a non-profit."[2196]

1008. Clean Energy Associations suggest two mechanisms to provide opportunities for states and interconnection customers to ensure that necessary transmission facilities are built. First, Clean Energy Associations would provide a "Transmission Alternative Right," through which states or interconnection customers could pay the difference between evaluated benefits and the level of benefits necessary to meet the applicable benefits threshold. Second, Clean Energy Associations would provide a "Transmission Expansion Right," which would allow states or interconnection customers to provide funding to expand transmission facilities beyond those identified in Long-Term Regional Transmission Planning. With respect to this second right, Clean Energy Associations contend that the funding parties should receive time-limited priority usage of additional transmission expansion that they fund and retain incremental capacity attributes associated with the expanded capability.[2197] Clean Energy Associations also suggest that the portion of the expanded Long-Term Regional Transmission Facility originally

[2196] *Id.* (citing *Ameren Servs. Co. v. FERC*, 880 F.3d 571 (D.C. Cir. 2018)).

[2197] Clean Energy Associations Initial Comments at 23-24 (citing Clean Energy Associations ANOPR Initial Comments at 76). Clean Energy Associations assert this would be consistent with Order No. 807. *Id.* (citing Clean Energy Associations ANOPR Initial Comments at 76-78; *Open Access & Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211, at P 109, *order on reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015)).

identified in the regional transmission plan would receive the applicable regional cost allocation.[2198]

1009. New Jersey Commission argues that allowing Relevant State Entities the opportunity to fund the cost of or part of the cost of transmission facilities would provide a way to value a transmission facility's public policy benefits and a mechanism for co-optimizing reliability and economic benefits while meeting public policy needs. However, New Jersey Commission states that, while the proposed 20-year transmission planning horizon should ensure that transmission providers identify opportunities for multi-driver transmission projects in sufficient time for states to provide funding, the Commission should mandate that transmission providers reach out to Relevant State Entities to inform them of such opportunities on a timely basis.[2199]

1010. SPP takes no position on the voluntary funding issue but states that its Regional State Committee developed a cost allocation framework that includes the option for entities to sponsor specific transmission projects, assuming cost responsibility without imposing burdens on others through the general rate structure. SPP states that this mechanism could be used by a state or states to fund projects that SPP otherwise would not select.[2200]

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[2198] *See id.*

[2199] New Jersey Commission Initial Comments at 28.

[2200] SPP Initial Comments at 22 (citing SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), § 7.2).

1011. While PPL supports the ability of states to fund the cost of, or a portion of the costs of, transmission facilities that otherwise would not meet selection criteria, PPL argues that the final rule should not require transmission providers to facilitate such an opportunity with states.[2201] APS contends that it is not appropriate for a Relevant State Entity to volunteer its ratepayers to fund, and APS to build, a transmission facility. APS explains that Arizona is a diverse state with several non-jurisdictional entities; as such, APS contends that the state would not have the authority to volunteer all the state's ratepayers to fund the transmission facility, which ultimately may burden transmission providers with additional costs and responsibilities.[2202]

### c. Commission Determination

1012. We modify the NOPR proposal and require transmission providers in each transmission planning region to include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria. We provide transmission providers with the flexibility to propose certain features of such a voluntary funding process in their compliance filings.[2203] However, this voluntary funding process

[2201] PPL Initial Comments at 19.

[2202] APS Initial Comments at 10.

[2203] *See* ISO-NE Initial Comments at 36; NARUC Initial Comments at 31-32 (requesting flexibility to design voluntary funding processes).

must be transparent and not unduly discriminatory or preferential and provide for the four components discussed below. Further, as with other aspects of the evaluation process and selection criteria, transmission providers must consult with and seek support from Relevant State Entities when developing a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that they propose to include in their OATTs.

1013. In setting forth the requirement that transmission providers include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria, we direct transmission providers to propose OATT provisions on compliance that describe: (1) the process by which the transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that Relevant State Entities and interconnection customers receive timely notice of such opportunities and provide a meaningful opportunity for Relevant State Entities and interconnection customers; (2) the period during which Relevant State Entities and interconnection customers may exercise the option to provide voluntary funding; (3) the method that transmission providers will use to determine the amount of voluntary funding required to ensure that the Long-Term Regional Transmission Facility meets the transmission providers' selection criteria; and (4) the mechanism through which transmission providers and Relevant State Entities or

interconnection customers will memorialize any voluntary funding agreement, e.g., a *pro forma* agreement in the OATT. We clarify that, for any portion of the costs of a selected Long-Term Regional Transmission Facility that is *not* voluntarily funded by a Relevant State Entity (or Entities) or interconnection customers, those remaining costs must be allocated according to the applicable Long-Term Regional Transmission Cost Allocation Method (or cost allocation method resulting from a State Agreement Process, if such a process is adopted by the transmission providers in the associated transmission planning region).

1014. We believe that requiring transmission providers to include a voluntary funding process in their OATTs ultimately may increase the number of Long-Term Regional Transmission Facilities that are selected. The voluntary funding processes that we are requiring transmission providers to include in their OATTs will allow Relevant State Entities and interconnection customers to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility, with any remaining costs allocated to beneficiaries in a manner that is at least roughly commensurate with the estimated benefits that they will receive. As such, a voluntary funding process will allow the development of Long-Term Regional Transmission Facilities that Relevant State Entities or interconnection customers believe are beneficial but that might not otherwise be selected.[2204] We also believe that such a voluntary funding process could help

[2204] *See, e.g.*, New Jersey Commission Initial Comments at 25-26 (arguing that voluntary funding would provide a way to value a transmission facility's public policy benefits and a mechanism for co-optimizing reliability and economic benefits while

transmission providers to avoid, manage, or resolve otherwise difficult disputes among stakeholders in their transmission planning regions, such as those arising from situations in which Relevant State Entities or interconnection customers value the development of certain Long-Term Regional Transmission Facilities differently.

1015. We acknowledge, consistent with APS's comments, that in certain states Relevant State Entities may not have the necessary authority to require all of that state's ratepayers to provide the funding needed to take advantage of voluntary funding opportunities.[2205] We do note, however, nothing in this final rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to the ability of any Relevant State Entity to voluntarily fund any costs of a Long-Term Regional Transmission Facility. Whether and to what extent a Relevant State Entity chooses to take advantage of an opportunity to voluntarily fund the costs of a Long-Term Regional Transmission Facility is dependent on whether that entity has the requisite authority to do so.

1016. In response to Ameren,[2206] we decline to determine at this point what effect *Ameren Services Co. v. FERC* may have on voluntary funding arrangements or the allocation of the costs of a transmission facility net of that voluntary funding, which may depend on how transmission providers propose to allow for voluntary funding opportunities.

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meeting public policy needs).

[2205] APS Initial Comments at 10.

[2206] Ameren Initial Comments at 21-22.

1017. We decline Clean Energy Associations' request that we require transmission providers to allow voluntary funding opportunities to expand a Long-Term Regional Transmission Facility beyond what was identified through Long-Term Regional Transmission Planning (e.g., voluntarily funding the construction of a 500 kV transmission line where a 345 kV transmission line was identified through Long-Term Regional Transmission Planning).[2207] While we recognize that there may be interest in providing additional opportunities for voluntary funding, we find that there is insufficient record evidence to support imposing this modification to the voluntary funding opportunity we require in this final rule. We note, however, that nothing in this final rule prohibits this type of voluntary funding approach and transmission providers may either seek to demonstrate that a proposal including such an approach is consistent with or superior to what is required by this rule, or else submit a filing under FPA section 205 to propose the inclusion in their OATTs of voluntary funding opportunities that go beyond those required in this final rule.

1018. Finally, in response to APPA,[2208] we decline to impose any specific requirement for transmission providers to file agreements that memorialize voluntary funding arrangements under FPA section 205. The Commission will evaluate on compliance the mechanism that transmission providers propose for memorializing voluntary funding

[2207] Clean Energy Associations Initial Comments at 23-24 (citations omitted).

[2208] APPA Initial Comments at 34-35 (citing *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024).

agreements between transmission providers and Relevant State Entities or interconnection customers, as applicable.

### 6. No Selection Requirement

#### a. NOPR Proposal

1019. The Commission did not propose in the NOPR to require that transmission providers select transmission facilities, even in the event that a transmission facility meets the selection criteria established by the transmission providers.[2209]

#### b. Comments

1020. Many commenters express opposition to any potential requirement under which the Commission would require transmission providers to select Long-Term Regional Transmission Facilities.[2210] For example, ISO-NE states that the final rule should be clear that transmission providers are not required to select any identified Long-Term Regional Transmission Facilities for inclusion in system plans or cost allocation

[2209] *See* NOPR, 179 FERC ¶ 61,028 at P 9 (noting that the proposed reforms related to regional transmission planning and cost allocation requirements, like those of Order Nos. 890 and 1000, are focused on the transmission planning process, and not on any substantive outcomes that may result from this process); *see also id.* P 241 (requiring transmission providers to propose selection criteria to identify and evaluate transmission facilities for *potential selection*).

[2210] *See, e.g.*, California Water Initial Comments at 14-15; Dominion Initial Comments at 18; Dominion Reply Comments at 8 (citing NARUC Initial Comments at 5-6, 39); ISO-NE Initial Comments at 35-36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Initial Comments at 46-47; NRECA Initial Comments at 48; NRECA Reply Comments at 4-8 (citations omitted); NYISO Initial Comments at 44 (citing *N.Y. Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,044, at P 125 (2014)); TANC Initial Comments at 10.

purposes, and NESCOE agrees.[2211] Ameren contends that a mandate to select any transmission facility may result in over-building the transmission system.[2212] Xcel makes a similar point, arguing that it would result in a loss of confidence in the transmission planning process. Furthermore, Xcel argues, transmission planning is subjective and removing all discretion from transmission planners would result in bad outcomes.[2213]

1021. SERTP Sponsors urge the Commission to make clear that there is no requirement for transmission providers to select Long-Term Regional Transmission Facilities based on long-term studies without specific express support and agreement of the relevant regulatory authorities and policy makers.[2214] NRECA asserts that transmission planning using a 20-year transmission planning horizon is an exercise fraught with uncertainty, and requests that the Commission clarify that it is not mandating that transmission providers select Long-Term Regional Transmission Facilities 20 years in advance.[2215] NRECA states that other commenters also expressed concerns about risks to consumers

[2211] ISO-NE Initial Comments at 35-36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO-NE Initial Comments at 35-36).

[2212] Ameren Initial Comments at 13 (citing Large Public Power Initial Comments at 10).

[2213] Xcel Initial Comments at 13-14.

[2214] SERTP Sponsors Initial Comments at 5; *see also* Alabama Commission Initial Comments at 3 (contending that Long-Term Regional Transmission Planning should not involve selection or construction obligations unless the affected state regulators support such actions).

[2215] NRECA Initial Comments at 27, 48.

associated with selecting transmission projects in the regional transmission plan for purposes of cost allocation 20 years before they may be needed.[2216]

1022. Dominion claims that Long-Term Regional Transmission Planning should not be a mandated development and construction plan of transmission facilities and argues that it should instead merely be a tool to help transmission providers understand where transmission needs may exist now and in the future.[2217]

1023. PJM requests that the Commission clarify that transmission providers can identify trends across multiple Long-Term Regional Transmission Planning cycles without needing to select specific transmission facilities, arguing that it should have the flexibility to open solicitations for transmission facilities as system needs arise.[2218]

1024. A few commenters favor selection mandates in at least some circumstances. For example, Eversource argues that the Commission should consider requiring transmission providers to address transmission needs that are identified in multiple Long-Term Scenarios or in the "high-impact, low-frequency event" scenario. Eversource contends

[2216] NRECA Reply Comments at 4-8 (citing APPA Initial Comments at 22, 24-36; California Municipal Utilities Initial Comments at 2-3, 5-7, 15; ELCON Initial Comments at 10; Large Public Power Initial Comments at 6–8, 11-13; Nebraska Commission Initial Comments at 2; New York Commission and NYSERDA Initial Comments at 8, 11-12; Pennsylvania Commission Initial Comments at 4-5; PJM Initial Comments at 59–62; TANC Initial Comments at 10).

[2217] Dominion Reply Comments at 8 (citing PIOs Initial Comments at 13, 28; NARUC Initial Comments at 5-6, 39).

[2218] PJM Reply Comments at 36-37.

that transmission providers otherwise risk failing to select transmission facilities that will greatly increase reliability, resiliency, and affordability.[2219]

1025. PIOs state that experience with Order No. 1000 demonstrates that some transmission providers may only do the bare minimum to comply and therefore may fail to select, allocate the costs of, or construct much needed transmission. As such, PIOs state, the Commission should require transmission providers to use good faith efforts to select recommended transmission facilities.[2220]

### c. Commission Determination

1026. The Commission did not propose in the NOPR, and we will not require in this final rule, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.[2221] This final rule improves regional transmission planning processes by ensuring that transmission providers identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities that resolve those needs and assess the benefits thereof, and provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities. In

[2219] Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

[2220] PIOs Initial Comments at 12-13.

[2221] *See, e.g.*, ISO-NE Initial Comments at 35-36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO-NE Initial Comments at 35-36); SERTP Sponsors Initial Comments at 5.

other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.

1027. We believe that transmission providers implementing Long-Term Regional Transmission Planning and developing regional transmission plans require the flexibility to balance competing interests in the transmission planning region and to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements.

1028. We clarify that nothing in this final rule prohibits transmission providers from proposing to impose upon themselves a requirement to select a Long-Term Regional Transmission Facility in certain circumstances. For example, transmission providers might propose selection criteria that would require them to select a Long-Term Regional Transmission Facility if it would meet a Long-Term Transmission Need that appears in multiple Long-Term Scenarios, or if it exceeded selection criteria by a pre-set margin.

### 7. Other Issues

#### a. Comments

1029. Clean Energy Associations argue that any transmission projects that are approved at the end of a transmission planning cycle should be included in updated models in the next transmission planning cycle, as well as in generation interconnection studies.[2222]

[2222] Clean Energy Associations Initial Comments at 10.

1030. R Street argues that the status quo selection process undermines the NOPR's objective of advancing efficient and cost-effective transmission expansion and that many transmission projects, especially reliability projects, are not subject to economic scrutiny. Therefore, R Street argues that the Commission should require that all transmission projects pass a cost-benefit analysis under the purview of an independent transmission planner and/or monitor across all Order No. 1000 transmission planning regions.[2223]

**b. Commission Determination**

1031. In response to Clean Energy Associations, we clarify that we are not imposing specific requirements regarding the treatment of selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles, beyond the overall requirements discussed in the Development of Long-Term Scenarios section of this final rule. As we explain above, selection is only one of a number of steps in the transmission development process, and we believe that it is appropriate to provide transmission providers flexibility on how to update their planning models in a manner that most effectively addresses the specifics of their regional transmission planning processes, consistent with the requirements of this final rule.

1032. Finally, we note that this final rule generally does not require transmission providers to replace or otherwise make changes to existing Order No. 1000 regional reliability and economic transmission planning and cost allocation processes. As such,

[2223] R Street Initial Comments at 10.

we decline to adopt R Street's proposal to require that all transmission projects pass a cost-benefit analysis.

### 8. Reevaluation

#### a. NOPR Proposal

1033. The Commission proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility. The Commission proposed that the existing transmission developer requirements would apply, including that the developer of the selected regional transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals necessary to develop and construct the transmission facility such that it meets the transmission needs of the transmission planning region.[2224] The Commission proposed that, to the extent the Relevant State Entities in a transmission planning region agree to a State Agreement

[2224] NOPR, 179 FERC ¶ 61,028 at P 247 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 442). The Commission also stated in Order No. 1000-A that, as part of the ongoing monitoring of the progress of a transmission facility once it is selected, the transmission providers in a transmission planning region must establish a date by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the facility is selected to address. If such critical steps have not been achieved by that date, then the transmission providers in a transmission planning region may "remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution." Order 1000-A,139 FERC ¶ 61,132 at P 442.

Process, as described in the Regional Transmission Cost Allocation section, the development schedule should also include relevant steps related to that process.[2225]

1034. The Commission noted that, given the longer-term nature of transmission needs driven by changes in the resource mix and demand, the required development schedule for a transmission facility selected may make it unnecessary for the developer to take actions or incur expenses in the near-term if the transmission facility will not need to be in service in the near-term. The Commission also noted that a transmission provider may make that Long-Term Regional Transmission Facility's selection status subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles, such that the previously selected transmission facility is no longer needed. The Commission proposed that transmission providers include in their selection criteria how they will address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2226]

**b. Comments**

1035. Some commenters argue that the Commission should allow or require transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2227] For example, Kansas Commission contends that transmission

[2225] NOPR, 179 FERC ¶ 61,028 at P 247.

[2226] *Id.* P 248.

[2227] *See, e.g.*, Ameren Initial Comments at 20-21 (citing NOPR, 179 FERC

providers should be able to de-select any transmission facility selected through Long-Term Regional Transmission Planning if other regional transmission planning processes do not establish a need for that transmission facility.[2228] Illinois Commission argues that periodic review and revision of the underlying modeling assumptions incorporated in Long-Term Scenarios will help to ensure that Long-Term Regional Transmission Planning allows transmission providers the opportunity to modify regional transmission plans.[2229]

1036. APPA supports the NOPR proposal, stating that "off ramps" from Long-Term Regional Transmission Planning are necessary to protect customers from the costs of transmission facilities that are rendered unneeded or inefficient by material changes in available resources, technology, load characteristics, or laws.[2230] APPA continues that the Commission should also require transmission providers to include in their selection criteria how they will address the selection status of previously selected transmission facilities in subsequent transmission planning cycles. APPA further argues that, to facilitate such review, the Commission should require transmission providers to have clear mechanisms for tracking costs and benefits of Long-Term Regional Transmission

¶ 61,028 at P 248).

[2228] Kansas Commission Initial Comments at 14.

[2229] Illinois Commission Initial Comments at 6.

[2230] APPA Initial Comments at 22 (citing APPA ANOPR Initial Comments at 9-10; APPA ANOPR Reply Comments at 4; APPA, et al., Statement of Bryce Nielsen, Docket No. RM21-17-000, at 2 (filed Nov. 12, 2021)).

Facilities and to file periodic cost tracking reports with the Commission so that stakeholders have an opportunity to comment.[2231]

1037. LS Power argues that transmission providers should perform "variance analyses" of all previously selected regional transmission facilities.[2232] LS Power contends that all variations in costs, from the initial regional planning estimate through project completion, should be maintained in a single publicly available database.[2233]

1038. Certain TDUs argue that the Commission should require each transmission provider, at the time it selects a transmission facility that is expected to be in service more than three years later, (1) to identify the key assumptions that drove its inclusion in the regional transmission plan and (2) to review triennially whether those key assumptions remain valid or have materially changed. To promote customer affordability by avoiding over-building or under-building transmission facilities, Certain TDUs contend that if these key assumptions have materially changed, the Commission should require transmission providers to evaluate whether any revisions are necessary with respect to such transmission facilities.[2234]

1039. Large Public Power argues that, following selection of transmission facilities in Long-Term Regional Transmission Planning, the Commission should require

[2231] *Id.* at 35-36.

[2232] LS Power Supplemental Comments at 13-15.

[2233] *Id.* at 13.

[2234] Certain TDUs Initial Comments at 20.

transmission providers to create a cost and risk management framework. Specifically, Large Public Power argues that the Commission should require transmission providers to develop and implement protocols requiring the developer of a transmission facility to file periodic reports with the Commission tracking anticipated project costs against cost projections and updating benefits information. In the period before construction begins, if such reports indicate that anticipated costs have exceeded an identified threshold, or that benefit-cost ratios have declined by an identified percentage, Large Public Power states that stakeholders could consider remedial action and the transmission developer could present stakeholders with mitigation plans. Further, if stakeholders do not reach consensus on the developer's mitigation plan, Large Public Power argues that stakeholders could petition the Commission to disallow regional cost allocation for the transmission facility. Finally, under Large Public Power's proposal, if the Commission disallowed regional cost allocation, the transmission developer would be eligible for abandoned plant cost recovery in the absence of imprudence.[2235]

1040. Large Public Power argues that its proposal would provide more protection to consumers than did Order No. 1000. Large Public Power further contends that its proposal is similar to, but more expansive than, MISO's existing variance analysis process, and that it would work together with the Commission's proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission

[2235] Large Public Power Initial Comments at 11-12.

Planning cycles.[2236] APPA agrees with Large Public Power's proposal and argues that all interested stakeholders should have the opportunity to participate in any process to reassess previously approved transmission projects.[2237]

1041. New York Commission and NYSERDA state that, while transmission providers can identify transmission needs using a 20-year transmission planning horizon, transmission facilities should be selected closer in time to when the need is anticipated to materialize. New York Commission and NYSERDA state the final rule should direct transmission providers to develop "off ramps" in Long-Term Regional Transmission Planning so that previously identified Long-Term Regional Transmission Facilities can be reevaluated as the facility's needed-by date approaches. New York Commission and NYSERDA state that conducting ongoing review can help reduce the risk of stranded costs.[2238]

1042. NRECA contends that selecting transmission projects 20 years in advance is not necessary or even workable. NRECA contends that under the Commission's proposal, transmission providers would select Long-Term Regional Transmission Facilities conditionally and wait until a subsequent Long-Term Regional Transmission Planning

[2236] *Id.* (citing NOPR, 179 FERC ¶ 61,028 at P 248; Order No. 1000, 136 FERC ¶ 61,051 at PP 7, 263, 329; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0)).

[2237] APPA Reply Comments at 11-12 (citing Large Public Power Initial Comments at 11-12).

[2238] New York Commission and NYSERDA Initial Comments at 12.

cycle to confirm that selection decision, at which point the transmission developer would become eligible to use the applicable regional cost allocation method. NRECA argues that the Commission should allow a transmission provider during such a subsequent cycle to find that a previously selected transmission facility is no longer needed, either because the transmission need no longer exists or because the facility is no longer the most efficient or cost-effective solution to meet the need.[2239]

1043. ISO-NE takes no position on the Commission's proposal but argues that the Commission should allow transmission providers the flexibility to determine the treatment of previously selected transmission projects based on outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2240]

1044. A number of commenters oppose or express concerns with the Commission's proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles. For example, AEP argues that, once selected through Long-Term Regional Transmission Planning, transmission providers should include transmission facilities in future scenario analysis except where a new study raises serious doubt that the transmission facilities continue to provide net benefits. AEP contends that re-studying such transmission facilities will lead to an endless cycle of study and

[2239] NRECA Initial Comments at 25-26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[2240] ISO-NE Initial Comments at 36.

ultimately underinvestment in necessary transmission infrastructure, as well as increased costs for customers.[2241] Similarly, Indicated PJM TOs argue that, once selected, transmission facilities should remain in the regional transmission plan unless there is serious doubt a transmission facility would provide net benefits.[2242]

1045. Avangrid argues that there must be a high bar in subsequent Long-Term Regional Transmission Planning cycles for removing a previously selected transmission facility from the regional transmission plan because transmission developers must have confidence that selection in Long-Term Regional Transmission Planning represents a "definitive directive[] to invest capital."[2243] Avangrid states that transmission facilities should not be de-selected unless there are changed circumstances that would make continued development of the project materially detrimental. Avangrid argues that otherwise, Long-Term Regional Transmission Planning effectively will be an informational exercise on which investors cannot rely.[2244]

1046. Eversource recommends that the Commission clarify that once transmission facilities are selected in a Long-Term Regional Transmission Planning cycle, they will not be subject to reevaluation, because such reevaluation would undermine the transmission planning process and deter transmission investment that the Commission is

[2241] AEP Initial Comments at 13-14.

[2242] Indicated PJM TOs Initial Comments at 11.

[2243] Avangrid Initial Comments at 11.

[2244] *Id.*

seeking to encourage.[2245] Similarly, Exelon argues that the Commission should clarify that the selection of transmission facilities identified in Long-Term Regional Transmission Planning should be a conclusive action that is reasonably final and on which transmission developers can rely. Exelon explains that Long-Term Regional Transmission Facilities are likely to be high-voltage backbone facilities that meaningfully impact power flows on the transmission system and argues that restudy or reconsideration should be the exception and not the rule, allowing for their inclusion in system planning models used for other purposes (e.g., regional transmission planning addressing reliability and economic transmission needs and generator interconnection studies).[2246]

1047. WIRES contends that the Commission should clarify that transmission providers need not reevaluate previously selected Long-Term Regional Transmission Facilities after updating Long-Term Scenarios. WIRES claims that doing so would disrupt transmission facility development and raise costs.[2247] Similarly, PPL argues that the Commission should exempt transmission facilities that are under construction or for which equipment has been purchased from any reevaluation in subsequent Long-Term Regional Transmission Planning cycles.[2248] Invenergy argues that while Long-Term Scenarios should be regularly reassessed and updated, these updates should apply only to

[2245] Eversource Initial Comments at 15-16.

[2246] Exelon Initial Comments at 17-18.

[2247] WIRES Initial Comments at 7.

[2248] PPL Initial Comments at 6.

future Long-Term Regional Transmission Planning cycles and should not result in re-assessment of previously selected transmission facilities.[2249]

### c. Commission Determination

1048. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to include in their OATTs provisions that require them—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected. These OATT provisions must meet the requirements set forth below, as well as the minimum requirements for transmission providers' broader evaluation process and selection criteria described above in the Minimum Requirements section.

1049. Specifically, we direct transmission providers to revise their OATTs to require reevaluation of any selected Long-Term Regional Transmission Facilities in the following three situations, subject to limitations that we set forth below: (1) delays in the development of a previously selected Long-Term Regional Transmission Facility would jeopardize a transmission provider's ability to meet its reliability needs or reliability-related service obligations;[2250] (2) the actual or projected costs of a previously selected Long-Term Regional Transmission Facility significantly exceed cost estimates used in

[2249] Invenergy Initial Comments at 4-5 (citing NOPR, 179 FERC ¶ 61,028 at app. B).

[2250] We note that this is the same as the requirement adopted in Order No. 1000. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000-A, 139 FERC ¶ 61,132 at P 442; NOPR, 179 FERC ¶ 61,028 at P 247 & n.395.

the selection of a Long-Term Regional Transmission Facility; or (3) significant changes in federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission providers' selection criteria.[2251]

1050. In addition, we require transmission providers to include specific criteria in their OATTs that they will use to determine when one of these three situations occurs, thereby triggering the reevaluation of a previously selected Long-Term Regional Transmission Facility. For example, with respect to exceeding cost estimates (the second situation listed above), transmission providers may propose a specific threshold of cost escalation (e.g., a percent of total facility cost) above which the transmission providers would reevaluate a previously selected Long-Term Regional Transmission Facility. As another example, with respect to delays (the first situation listed above), transmission providers may propose specific development milestones that, if missed, may jeopardize the transmission developer's schedule and ultimately a transmission provider's ability to meet its reliability needs or reliability-related service obligations. We provide transmission providers with flexibility to propose these criteria on compliance, subject to the requirement that, as with the transmission providers' selection criteria, the reevaluation criteria must seek to maximize benefits accounting for costs over time without over-building transmission facilities. As such, in establishing such criteria, we expect transmission providers will balance the need to provide transmission developers

[2251] NOPR, 179 FERC ¶ 61,028 at P 248.

with adequate investment certainty, absent which more efficient or cost-effective Long-Term Regional Transmission Facilities will not be developed, against the risk that, due to significant changes in circumstances, failing to reevaluate a selected Long-Term Regional Transmission Facility may result in the over-building of transmission. In addition, transmission providers must designate a point after which all selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation, such that the transmission developer of the selected Long-Term Regional Transmission Facility has adequate certainty to make investment decisions, e.g., when the facility's transmission developer has secured all relevant permits and authorizations for the Long-Term Regional Transmission Facility.

1051. Further, as discussed further below, transmission providers may not reevaluate any selected Long-Term Regional Transmission Facility on the basis of significant changes in federal, federally recognized-Tribal, state, or local laws or regulations unless, during the Long-Term Regional Transmission Planning cycle in which transmission providers selected the Long-Term Regional Transmission Facility, the Long-Term Regional Transmission Facility's targeted in-service date was in the latter half of the 20-year transmission planning horizon for Long-Term Regional Transmission Planning.

1052. We also require transmission providers to include in the reevaluation provisions in their OATTs the process and procedures that they will use to reevaluate a previously selected Long-Term Regional Transmission Facility, including the potential outcomes of reevaluation (e.g., taking no action, imposing a mitigation plan, reassigning the Long-Term Regional Transmission Facility to a different transmission developer, modifying

the Long-Term Regional Transmission Facility, removing the Long-Term Regional Transmission Facility from the regional transmission plan).[2252] In particular, transmission providers must describe the conditions under which they would remove a previously selected Long-Term Regional Transmission Facility from the regional transmission plan.[2253] We provide flexibility to transmission providers to propose such processes and procedures, subject to the following requirements. First, reevaluation on the basis of cost increases or significant changes in federal, federally-recognized Tribal, state, or local laws or regulations must be part of a subsequent Long-Term Regional Transmission Planning cycle following selection and must take into account not only the updated costs but also the updated benefits of the Long-Term Regional Transmission Facility.[2254] Second, in order to allow for reevaluation to occur, these processes and

[2252] *See, e.g.*, MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § IX.E (setting forth potential outcomes of MISO's variance analysis procedures). Mitigation plans would provide to transmission developers the opportunity to address the cause of the reevaluation. For example, where reevaluation occurs because there are delays in the development of a previously selected Long-Term Regional Transmission Facility, transmission providers might require the transmission developer to develop an operating procedure to ensure that the transmission providers are able to address the reliability need or meet the reliability-related service obligation in the period before the Long-Term Regional Transmission Facility will be placed in service.

[2253] We note that, in the event that the Long-Term Regional Transmission Facility was subject to competitive processes when it was selected, we do not require transmission providers to re-conduct these competitive processes in the event that the reevaluation process results in a change to the scope of the Long-Term Regional Transmission Facility. Instead, transmission providers have the flexibility to propose on compliance and explain whether, and if so when, they will re-run the competitive transmission development process as part of the reevaluation process.

[2254] Further, to perform the reevaluation analysis, we expect that transmission

procedures must include mechanisms for tracking costs so that transmission providers have an accurate way to determine if the actual or projected costs of the previously selected Long-Term Regional Transmission Facility exceed cost estimates by the relevant threshold, therefore requiring transmission providers to reevaluate that Long-Term Regional Transmission Facility. Third, the reevaluation processes and procedures must seek to maximize benefits accounting for costs over time without over-building transmission facilities. Again, we expect transmission providers in establishing these processes and procedures, including potential mitigation measures, to consider outcomes that enable more efficient or cost-effective Long-Term Regional Transmission Facilities to be developed, while addressing the risk of over-building.

1053. We note that in setting forth these requirements, we have carefully reviewed the record developed here and weighed commenters' countervailing arguments. We believe that the reevaluation requirements set forth above strike a careful balance between two broad objectives of Long-Term Regional Transmission Planning. On the one hand, we believe that transmission providers must have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities, which requires sufficiently long-term, forward-looking, and comprehensive regional transmission planning practices. Moreover, for selection to meaningfully result in the development of such more efficient

providers will use the updated Long-Term Scenarios and associated transmission system models that are developed for the Long-Term Regional Transmission Planning cycle in which the transmission provider reevaluates the selected Long-Term Regional Transmission Facility.

or cost-effective Long-Term Regional Transmission Facilities, it must provide adequate certainty to transmission developers to support capital investment.

1054. On the other hand, we also acknowledge the inherent uncertainty involved in predicting future transmission needs, and the continued selection of Long-Term Regional Transmission Facilities that no longer meet the transmission providers' selection criteria closer to the time that those facilities are expected to go into service could be costly for consumers. Where transmission providers have selected Long-Term Regional Transmission Facilities further out in the transmission planning horizon, and where transmission providers timely obtain updated information about significant changes to the costs or benefits of such facilities, we believe that transmission providers must, consistent with the requirements in this final rule, reevaluate a selected Long-Term Regional Transmission Facility in order to ensure that the facility continues to meet the transmission providers' selection criteria.

1055. In the NOPR, the Commission attempted to balance these objectives by proposing that, because the required development schedule of a previously selected Long-Term Regional Transmission Facility may not require its transmission developer to take actions or incur expenses in the near-term, transmission providers might be able to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.[2255] On further reflection, however, and after reviewing comments submitted in

[2255] NOPR, 179 FERC ¶ 61,028 at P 248.

response to the NOPR,[2256] we find that conditioning the selection of a Long-Term Regional Transmission Facility in this manner and on a routine basis may introduce too much uncertainty into transmission providers' evaluation and selection of Long-Term Regional Transmission Facilities.[2257] We agree with AEP that routine reevaluation would require repeated studies and ultimately could lead to underinvestment in Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.[2258] Therefore, we do not adopt the NOPR proposal to allow transmission providers to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.

1056. Nevertheless, we continue to believe that transmission providers may be reticent to select—and Relevant State Entities and other stakeholders may not support the selection of—certain Long-Term Regional Transmission Facilities in the absence of a requirement for transmission providers to reevaluate the selection of such facilities should significant new information become available that could give rise to concerns that those facilities no

[2256] *See, e.g.*, Exelon Initial Comments at 17-18 (arguing that selection should be "reasonably final" and that routine reevaluation would harm the certainty required for developing Long-Term Regional Transmission Facilities, inhibit efficient interconnection queue processing, and undermine system reliability as a whole).

[2257] For this reason, we are unpersuaded by NRECA's argument that transmission providers should conditionally select Long-Term Regional Transmission Facilities subject to confirmation in a subsequent Long-Term Regional Transmission Planning cycle. NRECA Initial Comments at 25-26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[2258] *See* AEP Initial Comments at 13-14.

longer meet the transmission providers' selection criteria.[2259] Further, as is required for regional transmission planning processes under Order No. 1000, transmission providers also must have the ability to take action when delays in developing a Long-Term Regional Transmission Facility risk jeopardizing a transmission provider's ability to meet its reliability needs or reliability-related service obligations.[2260]

1057. As discussed above, selection of a Long-Term Regional Transmission Facility is only one step in the process of developing, constructing, and placing that facility in service for the benefit of customers. Given the risks involved in transmission development, it is necessary to provide sufficient certainty to transmission developers and their financing partners that reevaluation will not lead to endless studies and protracted dispute. Therefore, we require transmission providers to set forth in their OATTs a reevaluation process, as outlined above, that ensures that any reevaluation of Long-Term Regional Transmission Facilities that have been selected will occur only in the circumstances that we have described.

1058. We agree with APPA that reevaluation—and in particular any determination of whether a Long-Term Transmission Need continues to exist or whether a Long-Term Regional Transmission Facility continues to meet the transmission providers' selection

[2259] *See, e.g.*, APPA Initial Comments at 22 (arguing that there should be "off ramps" protecting transmission customers from Long-Term Regional Transmission Facilities that, following selection, are rendered unnecessary or inefficient by intervening changes (citations omitted)).

[2260] Order No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000-A, 139 FERC ¶ 61,132 at P 442.

criteria—will require transmission providers to be able to track the costs of developing Long-Term Regional Transmission Facilities.[2261] We note above that transmission providers must propose on compliance the mechanism that they will use to track the costs of selected Long-Term Regional Transmission Facilities.

1059. As discussed above, however, we note that, when conducting a reevaluation of a selected Long-Term Regional Transmission Facility, transmission providers must update not only actual and projected costs but also their calculation of the benefits of the selected Long-Term Regional Transmission Facility. Such a requirement will ensure that transmission providers are comparing the relevant costs and benefits, i.e., the updated costs and benefits of the selected Long-Term Regional Transmission Facility, to determine whether the Long-Term Regional Transmission Facility continues to be a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. Because updating the calculation of the benefits of a Long-Term Regional Transmission Facility is not as straightforward as tracking costs, we require reevaluation on the basis of cost escalations or of changes in federal, federally-recognized Tribal, state, or local laws and regulations to occur as part of a subsequent Long-Term Regional Transmission Planning cycle. We find that this requirement is appropriate given the substantial time and resources that we expect will be necessary to update the underlying assumptions used in the transmission planning models, which must take place in order to update the calculation of the benefits of selected Long-Term Regional Transmission

[2261] APPA Initial Comments at 36.

Facilities for purposes of such reevaluations. Requiring transmission providers to update these assumptions and their transmission planning models, including all Long-Term Scenarios and any associated sensitivities, beyond a subsequent Long-Term Regional Transmission Planning cycle would introduce unnecessary disruptions and potentially impede the efficient conduct of the next Long-Term Regional Transmission Planning cycle.

1060. In response to Kansas Commission, we decline to allow transmission providers to remove a Long-Term Regional Transmission Facility from a regional transmission plan for purposes of cost allocation solely because other regional transmission planning processes do not establish a need for that transmission facility.[2262] Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes identify transmission needs differently, and we do not agree based on the requirements that we establish in this final rule for Long-Term Regional Transmission Planning that reevaluation based solely on transmission needs identified through existing Order No. 1000 regional transmission planning processes is appropriate. We also decline Certain TDUs' request that the Commission require transmission providers to identify certain key assumptions driving the selection of Long-Term Regional Transmission Facilities and to review these assumptions in subsequent Long-Term Regional Transmission Planning cycles. Long-Term Regional Transmission Planning will necessitate that transmission providers compile a wide range of information from

[2262] *See* Kansas Commission Initial Comments at 14.

multiple data sources, analyze the effect of that information, develop Long-Term Scenarios that provide a view into what Long-Term Transmission Needs may be, and evaluate Long-Term Regional Transmission Facilities in light of these multiple different scenarios. In this light, we believe that Certain TDUs' suggested approach would not capture the complex interactions of the various factors giving rise to Long-Term Transmission Needs.

1061. Finally, we note that a coalition of diverse interests, including transmission developer, utility, and consumer interests, jointly expressed support for a framework that would provide for reconsideration of a Long-Term Regional Transmission Facility where cost and benefit projections deviate substantially from those at the time of selection.[2263] We appreciate such efforts to bridge divergent interests to find common ground in a compromise proposal, and believe that the reevaluation requirements adopted here, like that widely supported compromise, strike a balance between competing interests.

### F. Implementation of Long-Term Regional Transmission Planning

#### 1. NOPR Proposal

1062. In the NOPR, the Commission proposed to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning efforts.

[2263] *See Advocates Advance Transmission Planning Cost Management Proposal At FERC*, Large Public Power Council (Mar. 6, 2024), https://www.lppc.org/news/lppc-and-advocacy-groups-advance-transmission-planning-cost-management-proposal-at-ferc (describing endorsements by LPPC, ACEG, CEBA, and NASUCA).

The Commission stated that it recognized the possibility that there may be overlap in the time horizon for the proposed Long-Term Regional Transmission Planning and existing near-term regional transmission planning processes and that they will likely inform each other.[2264] The Commission also stated that it is possible that, in some cases, transmission facilities selected to address transmission needs driven by changes in the resource mix and demand may provide near-term reliability or economic benefits, and thus potentially displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.

1063. In the NOPR, the Commission also sought comment on whether the Commission should host a periodic forum for transmission providers, transmission experts, relevant federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.[2265]

### 2. Comments

#### a. Comments on the Initial Timing Sequence

1064. Several commenters support requiring transmission providers to explain on compliance how Long-Term Regional Transmission Planning will interact with existing Order No. 1000 regional transmission planning processes.[2266] Several commenters urge

[2264] NOPR, 179 FERC ¶ 61,028 at P 253.

[2265] *Id.* P 255.

[2266] Ameren Initial Comments at 22-23; APPA Initial Comments at 5, 24-25; Idaho Commission Initial Comments at 5; National Grid Initial Comments at 19; NYISO Initial Comments at 13.

the Commission to allow regional flexibility with respect to coordination between existing Order No. 1000 regional transmission planning processes and Long-Term Regional Transmission Planning.[2267] NESCOE argues that it could be counterproductive and unnecessary for the Commission to dictate the initial timing of new processes to coordinate them with existing Order No. 1000 regional transmission planning processes.[2268] PPL stresses the need for clarity on how the existing Order No. 1000 regional transmission planning processes interacts with Long-Term Regional Transmission Planning and states that each transmission planning region will need to address how planned reliability and economic projects should or should not be reflected in, evaluated against, and affected by long-term studies.[2269]

1065. R Street states that the NOPR correctly identifies challenges in harmonizing existing Order No. 1000 and Long-Term Regional Transmission Planning. R Street argues that the two processes should use different time frames and assumptions, with timing optimized to account for uncertainty. R Street maintains that existing Order No. 1000 transmission planning should be conducted annually over a transmission planning horizon of up to five years and should account for only those generators that are existing,

[2267] Ameren Initial Comments at 22-23; Duke Initial Comments at 29; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51-52; NYISO Initial Comments at 13; Pacific Northwest State Agencies Initial Comments at 20.

[2268] NESCOE Initial Comments at 51-52.

[2269] PPL Initial Comments at 4.

under construction, or have interconnection agreements. R Street states that Long-Term Regional Transmission Planning should be conducted every two or three years over a 20-year transmission planning horizon and should account for representative generation development expectations and longer-term load growth. R Street posits that the long-term process should then feed into the near-term process, and transmission projects failing a cost-benefit test in one transmission planning cycle can roll over to the next in-kind cycle.[2270]

1066. PIOs contend that the different timing for Order No. 1000 transmission planning process cycles across transmission planning regions can create inconsistent assumptions, uncoordinated project identification between the two processes, confusion, and administrative burden.[2271] To address this concern, PIOs assert that the Commission should: (1) mandate Order No. 1000 regional transmission planning process cycles be no longer than Long-Term Regional Transmission Planning cycles and if shorter, divide Long-Term Regional Transmission Planning cycles evenly;[2272] (2) synchronize assumptions so that assumptions are identical for years where both a Long-Term Regional Transmission Planning cycle and an existing Order No. 1000 regional transmission planning cycle start; (3) clarify the time period for existing Order No. 1000

[2270] R Street Initial Comments at 10-11.

[2271] PIOs Initial Comments at 47.

[2272] As an example, if a transmission provider uses a 36-month Long-Term Regional Transmission Planning cycle, its Order No. 1000 transmission planning cycles should be 36, 18, or 12 months. *Id.*

regional transmission planning for economic and reliability needs; and (4) require transmission providers to clarify when results of one transmission planning process are incorporated into another, and require reasonable efforts to avoid one process disrupting the other.[2273]

### b. Comments on Periodic Forums

1067. Several commenters support the Commission's proposal to host a periodic forum for transmission providers, transmission experts, relevant federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.[2274] For example, AEP states that periodic forums would allow stakeholders to discuss best available data, modeling inputs, and techniques for calculating benefits.[2275] GridLab states that a periodic forum, along with follow-on technical conferences and a periodic forum, could promote greater convergence in planning methods among transmission providers.[2276]

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[2273] *Id.* at 48-49.

[2274] ACORE Initial Comments at 15; AEP Initial Comments 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19-20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35-36.

[2275] AEP Initial Comments at 31.

[2276] GridLab Initial Comments at 5.

1068. Pacific Northwest State Agencies suggest that the Commission could hold technical conferences or regional sessions similar to the Federal State Task Force on Electric Transmission.[2277] In contrast, PJM states that the periodic forum should be less formal than the technical conference format and that the Commission should consider using existing interconnection-wide organizations to host some of these forums.[2278] SPP also notes that there are existing forums that could be leveraged, such as the Eastern Interconnection Planning Collaborative.[2279]

1069. Some commenters recommend that the forums be held on an annual or a triennial schedule.[2280] MISO notes that, while the current pace of change might warrant multiple technical discussions to understand emerging trends, over the long term such technical forums may only be necessary when new industry trends are identified.[2281] Nevada Commission and Northwest and Intermountain suggest that the forum could be structured into two parts, separated by policy and technical discussion, by RTOs/ISOs and OATT transmission planning regions, or by Eastern and Western Interconnection.[2282]

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[2277] Pacific Northwest State Agencies Initial Comments at 20.

[2278] PJM Initial Comments at 77.

[2279] SPP Initial Comments at 24.

[2280] AEP Initial Comments at 31; Arizona Commission Initial Comments at 9; Nevada Commission Initial Comments at 12.

[2281] MISO Initial Comments at 57.

[2282] Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17.

1070. Dominion and Idaho Power oppose the Commission hosting additional periodic forums.[2283] Dominion recommends that the Commission use the existing Joint Federal-State Task Force on Electric Transmission instead.[2284] Idaho Power asserts that the most useful approach would be to allow transmission planning regions the time necessary to formulate processes that meet the Commission's requirements, and additional time for implementation and integration of those processes into current transmission planning processes.[2285]

### 3. Commission Determination

#### a. Initial Timing Sequence Implementation

1071. We adopt the NOPR proposal to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. Transmission providers must provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, we find that transmission providers must address the possible interaction between the transmission planning cycle for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. As the Commission stated in the NOPR, we recognize the possibility that there may be overlap in the time

[2283] Dominion Initial Comments at 15-16; Idaho Power Initial Comments at 8-9.

[2284] Dominion Initial Comments at 15-16.

[2285] Idaho Power Initial Comments at 8-9.

horizon for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes and that these processes will likely inform each other. Second, we find that transmission providers must address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. As the Commission noted in the NOPR, it is possible that, in some cases, Long-Term Regional Transmission Facilities selected to address Long-Term Transmission Needs may provide near-term reliability or economic benefits, and thus could displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.[2286]

1072. We find that transmission providers should have the flexibility to integrate the existing regional transmission planning processes with Long-Term Regional Transmission Planning in a manner that mitigates the potential for disruption of the existing regional transmission planning processes, and we note the agreement of some commenters on this point.[2287] However, we are also concerned that too much flexibility for transmission providers with respect to the date by which they must begin the first Long-Term Regional Transmission Planning cycle could lead to unnecessary delay in

[2286] NOPR, 179 FERC ¶ 61,028 at P 253.

[2287] Ameren Initial Comments at 22-23; Anbaric Initial Comments at 4-5, 22-27; CAISO Initial Comments at 2-3, 9, 17-20; Duke Initial Comments at 29; Indicated PJM TOs Initial Comments at 12; Large Public Power Initial Comments at 14-16; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51-52; NYISO Initial Comments at 13; PPL Initial Comments at 4; Pacific Northwest State Agencies Initial Comments at 20; Transmission Dependent Utilities Initial Comments at 4-5.

realizing these beneficial reforms for customers. Thus, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. However, we understand that it will likely be useful to align in some manner the Long-Term Regional Transmission Planning cycle with existing transmission planning cycles. In some cases, such alignment may not be possible to do within this one-year deadline. Therefore, transmission providers in a transmission planning region may propose to start the first Long-Term Regional Transmission Planning cycle on a date later than one year from the initial compliance filing due date, only to the extent needed to align transmission planning cycles. While we encourage transmission providers to align transmission planning cycles if useful, to ensure that there is no inappropriate delay to starting Long-Term Regional Transmission Planning, transmission providers in a transmission planning region that propose a commencement date of later than one year from the compliance due date must include adequate support explaining how the proposed date to begin the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region.

1073. In addition, we recognize commenters' concerns regarding the coordination of Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning processes, and we encourage transmission providers to address in their explanation how their proposed Long-Term Regional Transmission Planning would

facilitate moving beyond piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.[2288]

1074. With respect to the argument by NESCOE that it would be counterproductive and unnecessary for the Commission to dictate the initial timing of new processes,[2289] we disagree. We find that it is necessary to establish a requirement for transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final rule are due (subject to the limited exception described above), on which they will commence the first Long-Term Regional Transmission Planning Cycle, in order to guarantee that implementation will not be subject to unreasonable or unnecessary delay. With regard to the proposals made by PIOs and R Street,[2290] we decline to adopt these proposals because we lack the record to assess the impacts that these more prescriptive proposed requirements would have on existing transmission planning processes, and whether these proposals would work effectively across the differing transmission planning processes in each transmission planning region.

### b. Periodic Forums

1075. We believe that it will be beneficial for the Commission to host a periodic forum for transmission providers, transmission experts, relevant federal and state agencies, and

[2288] *See supra* Need for Reform section.

[2289] NESCOE Initial Comments at 51-52.

[2290] PIOs Initial Comments at 44-48; R Street Initial Comments at 10-11.

other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning, and note commenters' agreement on this point.[2291] Accordingly, the Commission will organize forums to share best practices in implementing Long-Term Regional Transmission Planning and provide notice and relevant details in advance of the forums.

## IV. Coordination of Regional Transmission Planning and Generator Interconnection Processes

### A. Need for Reform and Overall Reform

#### 1. NOPR Proposal

1076. In the NOPR, the Commission proposed to require that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s).[2292]

[2291] ACORE Initial Comments at 15; AEP Initial Comments 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19-20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35-36.

[2292] NOPR, 179 FERC ¶ 61,028 at P 166.

1077. The Commission preliminarily found that this requirement will support the establishment of just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates by addressing a potential barrier to integrating new sources of generation that may otherwise continue to exist absent such requirement in the regional transmission planning process.[2293] As the Commission explained in the NOPR, the interaction between regional transmission planning and cost allocation processes and the generator interconnection process is limited—the baseline regional transmission planning models generally only incorporate interconnection projects that have completed an interconnection facilities study and are therefore near the end of the generator interconnection process.[2294] The Commission stated, however, that where transmission system needs are repeatedly identified through generator interconnection processes, more efficient or cost-effective transmission expansion could be achieved through regional transmission planning and cost allocation that allocates costs in a manner that is at least roughly commensurate with estimated benefits and eliminates a potential barrier to entry for new generation resources.[2295]

[2293] *Id.* P 168.

[2294] *Id.* P 155 (citing ANOPR, 176 FERC ¶ 61,024 at P 23).

[2295] *Id.* P 161.

1078. Additionally, the Commission sought comment on how the proposed requirement to evaluate such facilities for selection should interact with existing regional transmission planning processes and Long-Term Regional Transmission Planning.[2296]

### 2. Comments

#### a. On the Overall Reform

1079. Multiple commenters express support for the general notion of coordinating the transmission planning and generator interconnection processes.[2297] Other commenters explicitly support the coordination proposal laid out in the NOPR,[2298] with some of these commenters arguing that the NOPR proposal does not go far enough (as described below).[2299]

1080. Other commenters offer more qualified support for the NOPR proposal. APPA and Exelon see value in the proposal but emphasize that any interconnection-related network upgrades that meet the specified criteria must independently satisfy any other

[2296] *Id.* P 174.

[2297] ACEG Initial Comments at 51-53; Clean Energy Buyers Initial Comments at 19; DC and Maryland Office of People's Counsel Initial Comments at 16; Fervo Reply Comments at 1; Handy Law Initial Comments at 8-9; Interwest Initial Comments at 10-11; Invenergy Initial Comments at 2; Ohio Commission Federal Advocate Initial Comments at 8; PIOs Initial Comments at 72-73; R Street Initial Comments at 7-8.

[2298] ACEG Initial Comments at 51-53; California Commission Initial Comments at 27; SDG&E Initial Comments at 3.

[2299] Acadia Center and CLF Initial Comments at 25-26; ACORE Initial Comments at 13.

applicable criteria for selection.[2300] Similarly, NRECA requests that the Commission clarify that interconnection-related network upgrades associated with withdrawn interconnection requests will not receive preferential treatment in Long-Term Regional Transmission Planning.[2301] Clean Energy Associations and ENGIE support the proposal but argue that the Commission's concern could be more efficiently addressed with better regional transmission planning.[2302]

### b. Requesting Additional Reform

1081. Some commenters suggest that the NOPR proposal does not go far enough to integrate the transmission planning and generator interconnection processes or to improve interconnection-related network upgrade cost allocation.[2303] ACORE argues that more dramatic reforms are necessary.[2304] Anbaric contends that a planning assessment should be conducted whenever an interconnection request triggers interconnection-related network upgrades on the larger transmission system beyond the interconnection

[2300] APPA Initial Comments at 31; Exelon Initial Comments at 11-13.

[2301] NRECA Reply Comments at 10-11.

[2302] Clean Energy Associations Initial Comments at 15; ENGIE Initial Comments at 5.

[2303] Anbaric Initial Comments at 7-9; Clean Energy Associations Initial Comments at 25-26; Concerned Scientists Initial Comments at 21-22; ELCON Initial Comments at 13-14; Enel Initial Comments at 4-5; Invenergy Initial Comments at 10-13; Invenergy Reply Comments at 12-13; PIOs Initial Comments at 72-73; Shell Reply Comments at 3-7.

[2304] ACORE Initial Comments at 13.

substation and associated facilities.[2305] ELCON states that Long-Term Regional Transmission Planning should be integrated with the generator interconnection queue.[2306] It suggests that the Commission hold regular workshops to review best practices for coordinating the interconnection queue, current regional transmission planning, and Long-Term Regional Transmission Planning to reduce interconnection queue backlogs, leading to larger regional transmission projects that would both incorporate interconnection-related transmission needs and be eligible for competitive bidding.[2307]

1082. Similarly, Enel urges the Commission to consolidate the generator interconnection process into the regional transmission planning process to allow transmission providers to jointly assess the benefits, and allocate the costs, of transmission projects that benefit system loads and new generation.[2308] Likewise, Shell suggests that the Commission integrate Long-Term Regional Transmission Planning and generator interconnection processes, requiring the use of the same benefits analysis under the same criteria, including reliability, economic, and public policy needs. Shell asserts that this approach would: increase opportunities to reduce costs to produce power and deliver it to load,

[2305] Anbaric Initial Comments at 7-8.

[2306] ELCON Initial Comments at 13-14.

[2307] *Id.* at 14-15.

[2308] Enel Initial Comments at 4-5 (citing Enel, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf (last visited Apr. 2024)).

unlock economies of scale and scope, improve processing times for generator interconnection requests, address first mover and free-rider risk, and potentially increase states' willingness to participate in cost allocation.[2309]

1083. Acadia Center and CLF argue that the proposal does not fully address shortfalls with the current method for cost allocation associated with interconnection-related network upgrades.[2310] They also express concern that the NOPR proposal would address a limited subset of generator interconnection needs and call for additional changes to better allocate the costs of interconnection-related network upgrades (especially those related to offshore wind development) to regional beneficiaries.[2311] Similarly, PIOs state the current cost allocation for interconnection-related network upgrades violates settled law that requires costs to be allocated both to cost causers and beneficiaries.[2312] Relatedly, Invenergy argues that the most significant factor influencing an interconnection customer's decision to leave the interconnection queue is typically the cost of assigned interconnection-related network upgrades.[2313]

1084. Invenergy also argues that interconnection-related network upgrades would remedy existing issues and should thus be addressed through the regional transmission

[2309] Shell Reply Comments at 3, 5, 6-7.

[2310] Acadia Center and CLF Initial Comments at 25-26.

[2311] *Id.* at 25.

[2312] PIOs Initial Comments at 72.

[2313] Invenergy Reply Comments at 14.

planning process.[2314] Invenergy asserts that some regions use different dispatch and other assumptions in the regional transmission planning and generator interconnection processes, which can result in persistent system overloads not being addressed through the regional transmission planning process.[2315] Similarly, Concerned Scientists aver that generator interconnection requests could be 10 years old when the NOPR proposal designates the related interconnection-related network upgrades as suitable for consideration in future Long-Term Scenarios.[2316] Concerned Scientists argue that the Commission should require the inclusion in Long-Term Scenarios of interconnection-related transmission needs that the generator interconnection process identified multiple times.[2317]

### c. Concerns with the Overall Reform

1085. Some commenters oppose the Commission's proposal.[2318] AEP, Ameren, CAISO, and Utah Division of Public Utilities argue that the proposal is unnecessary.[2319] Duke

[2314] *Id.* at 12.

[2315] *Id.*

[2316] Concerned Scientists Reply Comments at 22.

[2317] *Id.*

[2318] AEP Initial Comments at 6, 18; Ameren Initial Comments at 17; CAISO Initial Comments at 34; Duke Initial Comments at 4; Illinois Commission Initial Comments at 8-9; MISO Initial Comments at 44-47; PJM Initial Comments at 7, 85-86; PPL Initial Comments at 12.

[2319] AEP Initial Comments at 18-20; Ameren Initial Comments at 18; CAISO Initial Comments at 6, 34-35; Utah Division of Public Utilities Initial Comments at 7.

argues that the Commission's proposal is unnecessarily prescriptive, difficult to implement, and risks introducing significant subjectivity and complex administration into the transmission planning process.[2320] Ameren claims the proposal will result in inefficient regional transmission planning because it will not minimize total cost to end-use customers.[2321]

1086. Vistra argues that the NOPR proposal does not address how the newly created interconnection capacity will be allocated and how the timing and implementation of such upgrades would work.[2322]

1087. MISO contends that the Commission should not adopt prescriptive rules for integrating the generator interconnection and regional transmission planning processes, but instead continue to allow the RTOs/ISOs to develop those processes that best fit their footprint.[2323] MISO argues that expanding the generator interconnection process beyond its current five-year outlook would slow the generator interconnection process.[2324] MISO requests that if the Commission does not eliminate the NOPR proposal, as MISO would prefer, then the requirement should be altered so that transmission providers would only

[2320] Duke Initial Comments at 4, 20.

[2321] Ameren Initial Comments at 18.

[2322] Vistra Initial Comments at 33-34.

[2323] MISO Initial Comments at 44; MISO Reply Comments at 28.

[2324] MISO Reply Comments at 29.

be required to post a list of generator interconnection upgrades that met the defined criteria.[2325]

1088. CAISO disagrees with California Commission's comments that the NOPR proposal could improve CAISO's existing interconnection-related network upgrade provisions because the two processes have significantly different eligibility requirements, purposes, and impacts.[2326] CAISO further argues that the NOPR proposal could require transmission planners to study only outdated interconnection-related network upgrades.[2327]

1089. Mississippi Commission states that interconnection-related network upgrades should focus on reducing costs and providing price signals and not be included in Long-Term Regional Transmission Planning.[2328]

1090. Some commenters argue that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs instead of other reasons[2329] such as the project being

[2325] MISO Initial Comments at 45.

[2326] CAISO Reply Comments at 28-29 (citing California Commission Initial Comments at 27).

[2327] *Id.* at 32.

[2328] Mississippi Commission Reply Comments at 9.

[2329] CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

uneconomic,[2330] the project having insufficient site control or permitting delays,[2331] the project being speculative,[2332] or some other regulatory or economic factor.[2333]

1091. PJM recommends an alternative proposal for funding generation interconnections in which states play the major role.[2334] Under the PJM proposal, states that want to incent generation interconnections, perhaps to support a renewable portfolio standard, could fund a backbone transmission system to help facilitate these interconnections.[2335]

1092. Invenergy asks the Commission not to consider certain alternative proposals advanced by other commenters.[2336]

### d. Cost Allocation

1093. Some commenters oppose the NOPR proposal on the assumption that it could shift the cost for interconnection-related network upgrades from interconnection customers to load.[2337] In addition, PJM states that the Commission's proposal could lead to undue

[2330] American Municipal Power Initial Comments at 33-34; Indicated PJM TOs Initial Comments at 13-14; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2331] Duke Initial Comments at 20-21; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 8; PJM Initial Comments at 88-89.

[2332] Entergy Initial Comments at 25.

[2333] PJM Initial Comments at 89.

[2334] *Id.* at 89-90.

[2335] *Id.* at 90.

[2336] Invenergy Reply Comments at 15 (citing MISO Initial Comments at 45; PJM Initial Comments 85, 90-92).

[2337] APPA Initial Comments at 31; Industrial Customers Initial Comments at 13;

discrimination and would distort the price signal that generator developers should see to make reasonable investment decisions.[2338] Industrial Customers state that generators should be able to recover the costs of interconnection through market revenues if their projects are competitive.[2339] Industrial Customers further argue that under the cost causation principle, a new generator should pay for interconnection-related network upgrades if such upgrades are only required because of the generator's interconnection.[2340] Vistra asserts that, although the proposal shifts costs indirectly, the Commission still must rationally explain its decision to depart from the existing just and reasonable "but-for" policy of Order No. 2003.[2341]

1094. Other commenters oppose the Commission's proposed reform because it will increase the cost to serve load. AEP asserts that such a proposal would possibly result in the development of unnecessary transmission infrastructure, which would lead to increased transmission customer costs for no benefit.[2342] Dominion argues that this

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NRECA Initial Comments at 41-42 (citation omitted); NRECA Reply Comments at 8-9; PJM Initial Comments at 89-90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

[2338] PJM Initial Comments at 89.

[2339] Industrial Customers Initial Comments at 13-14.

[2340] *Id.* at 21-22.

[2341] Vistra Initial Comments at 9 (citation omitted).

[2342] AEP Initial Comments at 20.

proposal could result in over-building and excessive rates for transmission customers.[2343] TAPS asks the Commission to clarify that consideration of interconnection-related transmission needs would not foreclose transmission providers from proposing a cost allocation method that is different from the cost allocation for other types of Long-Term Regional Transmission Facilities.[2344]

**e. Interconnection Queue Gaming Considerations**

1095. Several commenters express concerns that the NOPR proposal would incentivize gaming by interconnection customers to promote development of interconnection-related network upgrades through the regional transmission planning process.[2345] Some commenters claim that the Commission's proposal could create a perverse incentive for interconnection customers to submit and withdraw multiple interconnection requests so that interconnection-related network upgrades can be considered for regional cost

[2343] Dominion Initial Comments at 32.

[2344] TAPS Initial Comments at 13-14.

[2345] Ameren Initial Comments at 18-19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7-8; EEI Initial Comments at 18; Eversource Initial Comments at 23-24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12-13; Shell Initial Comments at 29-30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

allocation,[2346] especially in transmission planning regions with lower thresholds for entering and maintaining a position in the interconnection queue.[2347]

1096. Pennsylvania Commission, Shell, Eversource, and US DOE recommend the Commission modify the NOPR proposal to limit or prevent gaming. Pennsylvania Commission argues that adding more commitments on the part of the interconnection customer or requiring a more thorough analysis of the reasons for withdrawal is an appropriate way of addressing the concern.[2348] Shell states that, to prevent gaming, the Commission should revise its proposal so that an upgrade is only eligible for inclusion in the Long-Term Regional Transmission Plan if it appears in one generator interconnection study cycle over a five-year period.[2349] Eversource asks the Commission to find that submitting and withdrawing interconnection requests simply so that the required interconnection-related network upgrades would be identified twice in the operative period, for example, would violate the Commission's regulations, including but not limited to the duty of candor and the prohibition of market manipulation.[2350] US DOE states that the Commission should strive to ensure that the reforms do not create the

[2346] Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33-34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

[2347] EEI Initial Comments at 18.

[2348] Pennsylvania Commission Initial Comments at 9.

[2349] Shell Initial Comments at 30.

[2350] Eversource Initial Comments at 23-24 (citing 18 CFR 35.41; 18 CFR 1c.2)

potential for gaming by generators, which, absent mitigation, could increase delays and backlogs in the interconnection queue.[2351]

1097. In response, Interwest argues that suggestions that increased coordination would result in gaming assumes that developers know in advance what interconnection-related network upgrades they will be assigned through the interconnection process.[2352] Interwest argues that, given the uncertainty about whether, and when, such a process could apply and result in selection and construction of facilities under Long-Term Regional Transmission Planning, it would not incentivize gaming.[2353] Similarly, Invenergy argues that developers would have no reasonable expectation that any interconnection-related network upgrade meeting the NOPR criteria ultimately would be selected through the multi-year regional transmission planning process and actually constructed on a timeline that accommodates the developer's generation facility.[2354] If the Commission is concerned about possible gaming, however, Invenergy urges the Commission to revise the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.[2355]

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[2351] US DOE Initial Comments at 27-28.

[2352] Interwest Reply Comments at 5-6 (citing EEI Initial Comments at 18).

[2353] *Id.* at 6.

[2354] Invenergy Reply Comments at 14.

[2355] *Id.* at 14-15.

### f. Miscellaneous

1098. SEIA asks the Commission to clarify that the phrase "interconnection-related transmission needs" would allow transmission providers to include either individual or aggregated transmission solutions that address specific needs.[2356] SEIA asks the Commission to require transmission providers to assume that these interconnection-related network upgrades will be built and include the interconnection-related network upgrades in their Long-Term Regional Transmission Planning.[2357]

1099. Several commenters argue that the reforms issued under Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, will address interconnection-related issues more appropriately than the NOPR proposal.[2358] Some commenters argue that the Commission should defer consideration of the NOPR proposal until the reforms issued under Order No. 2023 are implemented.[2359]

## 3. Need for Reform

1100. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements

[2356] SEIA Initial Comments at 14 (citing SPP, *2020 Integrated Transmission Planning Assessment Report*, at 87 (Oct. 27, 2020)).

[2357] *Id.*

[2358] Dominion Reply Comments at 8; Idaho Power Initial Comments at 6-7; Illinois Commission Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15.

[2359] Duke Initial Comments at 20; EEI Initial Comments at 18; Entergy Initial Comments at 24-25.

are unjust, unreasonable, and unduly discriminatory or preferential because they do not adequately consider certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been resolved due to the withdrawal of the underlying interconnection request(s). We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that there is insufficient coordination between the Commission's existing generator interconnection processes and regional transmission planning and cost allocation processes regarding interconnection-related transmission needs that are repeatedly identified in the generator interconnection process. As a result of this deficiency, transmission providers do not currently consider those identified interconnection-related transmission needs in their regional transmission planning processes, nor do they evaluate whether more efficient or cost-effective regional transmission solutions to these needs could be achieved through regional transmission planning processes and cost allocation. Accordingly, we find that existing regional transmission planning and cost allocation processes are insufficient to ensure just and reasonable rates, and we direct the reforms discussed below to address this deficiency.

1101. As explained in the NOPR,[2360] we are concerned about the prevalence of interconnection-related network upgrades being repeatedly identified in the generator interconnection process in multiple interconnection queue cycles during a short period of time (e.g., five years) but not being developed because the interconnection request(s)

[2360] NOPR, 179 FERC ¶ 61,028 at PP 161-165.

driving the need for the upgrade are withdrawn. The record indicates that the level of spending on interconnection-related network upgrades has dramatically increased in recent years, escalating the cost of interconnecting new generation to the transmission system.[2361] The evidence also suggests that this trend is leading to more and more interconnection customers withdrawing their interconnection requests in the face of significant costs associated with interconnection-related network upgrades.[2362] For example, between January 2016 and July 2020, 245 generation projects in advanced stages in the MISO generator interconnection process withdrew from the queue, with the project developers citing high interconnection-related network upgrade costs as the primary reason for their withdrawal.[2363] While interconnection customers may choose to withdraw from the interconnection queue for a number of reasons, in recent years, the deciding factor has increasingly become the interconnection customer's "sticker shock" at its cost responsibility for interconnection-related network upgrades.[2364]

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[2361] *See* ICF Resources, LLC, *Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, 2 (Sept. 9, 2021), https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf (ICF Sept. 2021 Interconnection Report); Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy*, 14 (2021)), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf (ACEG 2021 Interconnection Report).

[2362] ACEG 2021 Interconnection Report at 17.

[2363] *Id.* (naming the high cost of interconnection-related network upgrades as the fundamental problem that interconnection queue reform has failed to address thus far).

[2364] *See* ACORE ANOPR Comments at 12; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and

1102. When interconnection customers withdraw from the interconnection queue, the identified interconnection-related network upgrades associated with those interconnection customers remain unbuilt and the underlying interconnection-related transmission needs go unaddressed. In many cases, when the interconnection-related transmission need is not addressed via development of interconnection-related network upgrades in one interconnection queue cycle, the same interconnection-related transmission need—and oftentimes the same or a substantially similar interconnection-related network upgrade—will appear in subsequent interconnection queue cycles. One study, which analyzed 12 specific interconnection-related network upgrades identified by MISO and SPP, found that SPP identified three of the upgrades in two interconnection queue cycles and one in three interconnection queue cycles, and MISO identified three of the upgrades in two interconnection queue cycles and two in three interconnection queue cycles.[2365] In other words, both SPP and MISO were repeatedly identifying the same interconnection-related network upgrades as interconnection customers withdrew from the interconnection queue, leaving later-in-time interconnection customers to address the same interconnection-related transmission needs.

1103. Where interconnection-related transmission needs are repeatedly identified in interconnection studies, the implication may be that the area, despite the potentially

Intermountain Initial Comments at 14; *see also* Order No. 2023, 184 FERC ¶ 61,054 at P 41; Order No. 2023-A, 186 FERC ¶ 61,199 at P 14.

[2365] ICF Sept. 2021 Interconnection Report at 25-26.

prohibitive interconnection costs if borne by one or a small number of interconnection customers, is otherwise desirable for generators to locate (e.g., it is located close to fuel sources). This repeated interest in accessing the transmission system, combined with the lack of available transmission capacity and prohibitive costs of interconnection-related network upgrades, together create a barrier to accessing the transmission system and establish a known interconnection-related transmission need. We find that this barrier to entry can hinder the timely development of new generation, thereby stifling competition in wholesale electricity markets and limiting access to lower-cost generation.[2366] We find that existing regional transmission planning processes do not adequately consider or account for this specific set of interconnection-related transmission needs that go unaddressed in the generator interconnection processes. By failing to consider such interconnection-related transmission needs, the regional transmission planning process is unable to identify the more efficient or cost-effective regional transmission solutions.

1104. Moreover, the Commission has long recognized that interconnection-related network upgrades provide transmission benefits that extend beyond the interconnection

[2366] The Commission has previously found that policies eliminating barriers to entry for generation resources can enhance competition in bulk power markets. *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at PP 694 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220 at P 579, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); Order No. 2023, 184 FERC ¶ 61,054 at P 44. Limited access to new and more competitive supplies of generation can increase the energy rates paid by wholesale customers. Order No. 2023, 184 FERC ¶ 61,054 at P 43.

customer.[2367] By upgrading the transmission system in a piecemeal fashion through the generator interconnection process, as described above, the current regional transmission planning paradigm can impose costs on interconnection customers for transmission facilities that provide benefits beyond those received by the interconnection customer. This paradigm allocates transmission costs in a way that may not be roughly commensurate with the distribution of benefits, a result that can lead to unjust and unreasonable rates. The reform adopted below requires the consideration of regional transmission facilities to meet interconnection-related transmission needs repeatedly identified in the generator interconnection process in the Order No. 1000 regional transmission planning and cost allocation processes, which we believe will result in more efficient or cost-effective regional transmission expansion, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which can enhance competition in wholesale electricity markets and facilitate access to lower-cost generation). In turn, we expect that these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1105. Additionally, as discussed further below, we disagree with commenters that question the necessity of this reform. In addition to our findings that this reform will help ensure just and reasonable rates, we find that the specific purpose of this reform—to

[2367] *See, e.g.*, Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that "[f]acilities beyond the Point of Interconnection [(i.e., interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users").

require transmission providers to evaluate certain interconnection-related transmission needs—is not a requirement of any existing process. Additionally, we find that the qualifying criteria established by this reform will ensure that the reform avoids placing an onerous burden on transmission providers. Finally, we disagree that this reform is overly prescriptive; it does not dictate a specific result or require that transmission providers select a regional transmission facility to address identified interconnection-related transmission needs. This reform merely requires consideration of these interconnection-related transmission needs in the regional transmission planning process.

#### 4. Commission Determination

1106. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning processes in their OATTs, consistent with the requirements in this final rule, to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process, as more fully described below. We find that this requirement will ensure that more efficient or cost-effective transmission expansion can be effectuated through regional transmission planning processes and will eliminate a potential barrier to entry for new generation resources, thereby enhancing competition in wholesale electricity markets and facilitating access to lower-cost generation. As a result, this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1107. In this final rule, we adopt the NOPR proposal with modification. First, we require transmission providers to evaluate for selection regional transmission facilities to address certain identified interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in Long-Term Regional Transmission Planning. Second, we modify the NOPR proposal to require that an interconnection-related network upgrade associated with identified interconnection-related transmission needs must satisfy *both* the minimum cost and voltage criteria proposed in the NOPR to qualify for evaluation for selection.

1108. In recent years, spending on interconnection-related network upgrades has increased dramatically, and the high cost of interconnection is increasing the rate at which generators withdraw from the interconnection queue.[2368] While interconnection customers may withdraw for multiple reasons, the record in this proceeding shows that, in recent years, the deciding factor in many cases of withdrawal has become the interconnection customer's cost responsibility for expensive interconnection-related network upgrades.[2369] Consequently, interconnection customers are unlikely to resolve these interconnection-related transmission needs through the generator interconnection process.

[2368] ACEG 2021 Interconnection Report at 17.

[2369] NOPR, 179 FERC ¶ 61,028 at P 162; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and Intermountain Initial Comments at 14.

1109. Where interconnection-related transmission needs are repeatedly identified but not constructed, the implication is that, despite the potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers, there are compelling reasons, such as proximity to fuel sources, why generators seek to locate a point of interconnection at a specific location or locations associated with transmission constraints. When interconnection customers that have invested time and resources in engaging in the generator interconnection process choose to withdraw rather than fund interconnection-related network upgrades, it becomes increasingly apparent that interconnection customer(s) are unlikely to resolve interconnection-related transmission needs through the generator interconnection process.

1110. At the same time, the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer.[2370] As a result, planning these types of upgrades to the transmission system in a piecemeal fashion, exclusively through the generator interconnection process, limits the development of transmission facilities that would

[2370] *See, e.g.*, *Entergy Svs., Inc. v. FERC*, 391 F.3d 1240, 1247-48 (2004); Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that "[f]acilities beyond the Point of Interconnection [(i.e., interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users"); *see also* ACORE ANOPR Comments, Ex. 5 at 4-7; CAISO ANOPR Comments at 53-54 (stating that in CAISO "transmission facilities at 200 kV and above are eligible for regional cost allocation," including location-constrained resources interconnection facilities, because "this voltage threshold . . . recognizes that high voltage transmission facilities support and provide benefits to all customers to the CAISO grid").

provide benefits to the transmission system beyond those received by the interconnection customer. This is the case where interconnection-related network upgrades of substantial cost are repeatedly identified to address interconnection-related transmission needs, but those needs continue to go unresolved through the generator interconnection process. In such cases, it may be more efficient or cost-effective to address such needs through the regional transmission planning and cost allocation process. Therefore, reforms are necessary to require interconnection-related transmission needs associated with interconnection-related network upgrades that are repeatedly identified in the generator interconnection process to be evaluated through the regional transmission planning and cost allocation process. We believe that this approach will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation).[2371] As a result, these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

[2371] While in this portion of the final rule we discuss the requirement that transmission providers evaluate in their existing regional transmission planning and cost allocation processes regional transmission facilities that address certain interconnection-related needs, we also expect that many of the other reforms in this final rule regarding Long-Term Regional Transmission Planning will address the difficulties generators face in interconnecting to the transmission system and the cost allocation mismatch described here, including required Factor Category Six, interconnection requests and withdrawals.

1111. While we require transmission providers to evaluate regional transmission facilities that address certain interconnection-related transmission needs identified by this reform in the existing Order No. 1000 regional transmission planning and cost allocation processes, we allow for flexibility in how transmission providers evaluate such facilities for selection. Transmission providers may adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability processes) to evaluate and potentially select these types of transmission facilities. By not requiring a specific process, we permit transmission providers to propose the best method to incorporate this requirement within their existing regional transmission planning processes. We also encourage transmission providers to consider, as part of the evaluation process, whether regional transmission facilities that address certain identified interconnection-related transmission needs may also address other regional transmission needs more efficiently or cost-effectively.

1112. Several commenters suggest alternative reforms to coordinate or consolidate regional transmission planning and generator interconnection processes or to modify existing cost allocation criteria.[2372] We find these requests to be outside the scope of this proceeding and lacking in record support to adequately consider whether to adopt them in this final rule. In this final rule, we are addressing the narrow issue of interconnection-related transmission needs being repeatedly identified yet continuing to go unresolved

[2372] *E.g.*, Enel Initial Comments at 4-5.

through the generator interconnection process, even though it may be more efficient and cost-effective to evaluate such needs through the regional transmission planning and cost allocation process.

1113. We find uncompelling general arguments from commenters that oppose the Commission's proposal because the reform addresses a deficiency in existing regional transmission planning and cost allocation processes, will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates, is not unduly burdensome, and does not dictate a particular outcome. The level of prescriptiveness of this reform strikes the right balance between an open-ended requirement, which might not address the need for reform, and a very prescriptive requirement that could be overly burdensome to transmission providers.

1114. We are unpersuaded by Ameren's argument that this reform will result in inefficient regional transmission planning because it will not minimize the total cost to end-use customers.[2373] As explained above, this reform will enable transmission providers to identify through regional transmission planning the more efficient or cost-effective transmission solution to address an interconnection-related transmission need.

1115. We clarify in response to Vistra that transmission providers must make the newly created interconnection capacity equally available to all interconnection and transmission customers consistent with the Commission's open access policy.[2374] Any interconnection

[2373] Ameren Initial Comments at 18.

[2374] Vistra Initial Comments at 33-34.

customers whose interconnection requests related to the initial identification of the interconnection-related transmission need would not have any priority rights to that newly created interconnection or transmission capacity. Additionally, we clarify, in response to NRECA's request, that we are not requiring interconnection-related network upgrades associated with withdrawn interconnection requests to be given preferential treatment in regional transmission planning.[2375]

1116. In response to commenters arguing that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs,[2376] we explain that we are not requiring transmission providers to evaluate regional transmission facilities that address interconnection-related transmission needs for every withdrawn interconnection request. Instead, this reform is focused only on certain interconnection-related transmission needs that meet the specific qualifying criteria detailed below. We do not assume that where these criteria are met, the relevant interconnection customers have necessarily withdrawn from the interconnection queue solely due to high interconnection-related network upgrade costs. Rather, we determine that these criteria only suggest that high costs were *likely* a factor prompting, or at least contributing to, the relevant withdrawals. We conclude that where the criteria are met, there may be an opportunity for a more efficient

[2375] NRECA Reply Comments at 10-11.

[2376] CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

or cost-effective regional transmission solution, such that an evaluation of the relevant interconnection-related transmission need(s) is appropriate.

1117. We are not persuaded to reject this reform based on commenters' assertions that this reform will shift the costs of interconnection-related network upgrades from interconnection customers to load.[2377] This final rule requires transmission providers to evaluate in their existing Order No. 1000 regional transmission planning and cost allocation processes regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process. Transmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply, and this final rule does not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process. If a regional transmission facility that addresses identified interconnection-related transmission needs is not selected as part of the regional transmission planning process, then the associated regional cost allocation method would not apply; however, if the

[2377] APPA Initial Comments at 31; Industrial Customers Initial Comments at 13; NRECA Initial Comments at 41-42 (citation omitted); NRECA Reply Comments at 8-9; PJM Initial Comments at 89-90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

facility is selected, then the regional transmission planning process has determined that the regional transmission facility is a more efficient or cost-effective regional transmission solution. Additionally, if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits.

1118. In response to TAPS' request that the Commission clarify that regions may propose differing cost allocation methods for transmission facilities selected to address interconnection-related transmission needs versus transmission facilities selected to address other types of transmission needs,[2378] we clarify that the requirements adopted here merely create an obligation for transmission providers to evaluate regional transmission facilities that address certain identified interconnection-related transmission needs in the existing regional transmission planning and cost allocation processes. As such, to the extent that transmission providers wish to propose further changes to their Order No. 1000 regional transmission planning cost allocation method(s) because of this requirement, they would need to do so in separate FPA section 205 filings rather than on compliance with this final rule.

1119. We disagree with commenters that the requirements adopted herein will incentivize gaming by interconnection customers to include interconnection-related network upgrades in the regional transmission planning process.[2379] We also disagree

[2378] TAPS Initial Comments at 13-14.

[2379] Ameren Initial Comments at 18-19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7-8;

with commenters that claim that interconnection customers will submit spurious interconnection requests.[2380] Interconnection requests require significant financial commitments from the interconnection customer (e.g., application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023,[2381] and therefore we find it unlikely that an interconnection customer would submit multiple interconnection requests (in multiple queue cycles) in order to trigger this requirement because of the possibility that transmission providers may eventually develop an interconnection-related network upgrade by selecting it in a regional transmission plan for purposes of cost allocation. An interconnection customer would face several risks in pursuing such a strategy, including the risk that the regional transmission solution for the interconnection-related transmission need is not selected, and the risk that the newly created interconnection or transmission capacity is allocated to a different transmission or interconnection customer. For these reasons, we decline to

EEI Initial Comments at 18; Eversource Initial Comments at 23-24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12-13; Shell Initial Comments at 29-30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

[2380] Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33-34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

[2381] *See, e.g.*, Order No. 2023, 184 FERC ¶ 61,054 at P 502.

adopt Invenergy's request to modify the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.[2382]

1120. In response to Eversource's request that the Commission clarify that submitting and withdrawing interconnection requests with the intent of requiring transmission providers to evaluate the associated interconnection-related transmission needs in their regional transmission planning process is in violation of the Commission's regulations, including but not limited to the duty of candor and prohibition of market manipulation,[2383] as noted above, the generator interconnection process requires significant financial commitments for interconnection requests to enter and proceed in the queue, and many transmission providers have imposed additional readiness requirements to encourage early withdrawal of non-viable interconnection requests. For these reasons, we disagree with the gaming concerns raised by Eversource.[2384]

1121. We also grant SEIA's request to clarify that the phrase "interconnection-related transmission needs" allows transmission providers to identify individual regional transmission solutions to address each identified interconnection-related transmission need, or an aggregate regional transmission solution to address multiple interconnection-

[2382] Invenergy Reply Comments at 14-15.

[2383] Eversource Initial Comments at 23-24 (citing 18 CFR 35.41; 18 CFR 1c.2).

[2384] While we are not concerned about gaming here, to the extent that there is evidence of a false representation or gaming of the market rules, a referral to the Office of Enforcement may be appropriate to determine whether a violation of the Commission's regulations has occurred.

related transmission needs. In response to commenters arguing that the reforms issued under Order No. 2023 will address interconnection-related issues more appropriately than the NOPR proposal,[2385] we explain that the reforms in this rulemaking are intended to address situations when interconnection-related network upgrades are repeatedly identified but not constructed and instances when regional transmission solutions to address the needs that would have been addressed by those interconnection-related network upgrades would provide widespread transmission benefits that extend beyond the interconnection customer, which are not addressed in Order No. 2023.

### B. Transmission Planning Process Evaluation

#### 1. NOPR Proposal

1122. In the NOPR, the Commission proposed to require the transmission providers in each transmission planning region to consider regional transmission facilities that address interconnection-related transmission needs pursuant to the proposed coordination reform through the Long-Term Regional Transmission Planning process proposed in the NOPR. Specifically, the Commission proposed to require that transmission providers in each transmission planning region incorporate the specific interconnection-related transmission needs identified through the coordination reform as a factor used to develop

[2385] Dominion Reply Comments at 8; Idaho Power Initial Comments at 6-7; Illinois Commission Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 15.

Long-Term Scenarios in the Long-Term Regional Transmission Planning proposed in the NOPR.[2386]

### 2. Comments

1123. Several commenters assert that the NOPR proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support interconnections.[2387] For example, Xcel argues that Long-Term Scenarios will be driven by the same factors that cause interconnection customers to make interconnection requests, such as optimal geographic locations for generation development.[2388] Similarly, EEI states that Long-Term Regional Transmission Planning, if properly implemented, already takes into account factors that support generator interconnection.[2389]

1124. Some of these commenters further claim that the Commission's coordination proposal's reliance on backward-looking interconnection needs would be less effective than planning on future system interconnection needs. CAISO argues that the Commission's proposal is backward-looking and therefore will not promote productive,

[2386] NOPR, 179 FERC ¶ 61,028 at P 167.

[2387] AEP Initial Comments at 19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8-9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

[2388] Xcel Initial Comments at 15.

[2389] EEI Initial Comments at 18.

forward-looking transmission planning.[2390] Vistra claims that an effective transmission planning process will identify interconnection needs and provide solutions within the context of a future system, rather than relying on prior interconnection studies addressing a specific generator interconnection request.[2391] Similarly, ISO/RTO Council recommends that the Commission direct transmission planners to consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis, rather than the coordination proposal's backwards-looking process.[2392]

1125. MISO states that because the generator interconnection process is designed to identify the minimum amount of interconnection-related network upgrades to interconnect new resources, Long-Term Regional Transmission Planning is the proper avenue to holistically evaluate system needs. MISO notes that it already has a mechanism in place to include interconnection-related network upgrades in its Long-Range Transmission Plan process if the interconnection-related network upgrade is found to have region-wide benefits.[2393]

### 3. Commission Determination

1126. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to evaluate regional transmission facilities

[2390] CAISO Initial Comments at 6, 34-35.

[2391] Vistra Initial Comments at 33.

[2392] ISO/RTO Council Initial Comments at 9.

[2393] MISO Initial Comments at 44, 46-47; MISO Reply Comments at 29.

that address certain interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes instead of in Long-Term Regional Transmission Planning. We find that this modification will better alleviate transmission limitations by providing a starting point for identifying and evaluating regional transmission solutions that are more efficient or cost-effective when analyzed in the near term.[2394] Specifically, requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes will allow such needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions. Evaluation of interconnection-related transmission needs in the existing Order No. 1000 regional transmission planning and cost allocation processes is most appropriate because such evaluation would occur at shorter intervals and would likely result in more expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.

1127. We agree with commenters that future interconnection-related transmission needs will be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios. Nonetheless, for the reasons described above, we find that current interconnection-related transmission needs can be considered more effectively through the nearer-term existing Order No. 1000 regional

[2394] *See* NOPR, 179 FERC ¶ 61,028 at P 165.

transmission planning and cost allocation processes. As such, we disagree with commenters that assert that the Commission's proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support generator interconnections.[2395] That said, we emphasize that, as transmission providers gain experience with Long-Term Regional Transmission Planning, we anticipate that they will identify fewer interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process because transmission providers will plan to address Long-Term Transmission Needs, including those driven by Factor Category One: federal, federally-recognized Tribal, state, and local laws and regulations that affect the future resource mix and demand; Factor Category Two: federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; Factor Category Six: generator interconnection requests and withdrawals, and Factory Category Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, through Long-Term Regional Transmission Planning.

1128. Some commenters, including Vistra and ISO/RTO Council, claim that the NOPR proposal to rely on needs identified in prior interconnection studies would be less effective at planning for interconnection-related transmission needs compared to more

[2395] AEP Initial Comments at 18-19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8-9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

future-oriented approaches. We agree that an effective regional transmission planning process will identify interconnection-related transmission needs and evaluate regional transmission solutions to those needs within the context of a future system. We further agree that transmission providers should consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis. For these reasons, we require transmission providers to incorporate seven specific categories of factors in their development of Long-Term Scenarios used in Long-Term Regional Transmission Planning, including Factory Category Six: generator interconnection requests and withdrawals. However, we disagree that the coordination proposal should not rely on past results from the generator interconnection process or specific interconnection requests in determining what interconnection-related transmission needs should be evaluated in the existing Order No. 1000 regional transmission planning and cost allocation processes. Interconnection-related network upgrades repeatedly identified in past interconnection studies are strongly indicative that a location (despite presenting potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers) is otherwise valuable for location of new generation.

1129. Finally, because we are modifying the NOPR proposal to no longer apply to Long-Term Regional Transmission Planning, commenters' specific concerns that this proposal is duplicative to the categories of factors requirements in the development of Long-Term Scenarios are moot.

### C. Qualifying Criteria

#### 1. NOPR Proposal

1130. In the NOPR, the Commission proposed to require that transmission providers evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (beginning at the time of the withdrawal of the first underlying interconnection request); (2) the interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV and/or an estimated cost of at least $30 million; (3) those interconnection-related network upgrades have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the upgrade has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.[2396]

[2396] NOPR, 179 FERC ¶ 61,028 at P 166.

1131. The Commission proposed that the initial five-year time period begin five calendar years prior to the initial effective date of the Commission-accepted tariff provisions proposed to comply with this reform such that, upon the Commission's acceptance of such tariff provisions, the transmission provider would consider interconnection-related network upgrades identified to address the same interconnection-related transmission need in at least two interconnection queue cycles in the five calendar years prior to the effective date established in the order accepting those tariff revisions.[2397] The Commission also proposed to require that transmission providers in each transmission planning region consider whether the interconnection-related transmission need for which the transmission provider identified the interconnection-related network upgrade is the same in multiple interconnection queue cycles.[2398] That is, if an interconnection-related transmission need is driving the identification of an interconnection-related network upgrade on the transmission system in one interconnection queue cycle and an interconnection-related network upgrade with, for example, a different voltage, starting point, or ending point is identified in the next interconnection queue cycle to address the same interconnection-related transmission need, then the first criterion of the proposed coordination reform would be satisfied.[2399] The Commission stated that it believes that this approach will appropriately account for differences in technology, study

[2397] *Id*. P 170.

[2398] *Id*. P 171.

[2399] *Id*.

assumptions, system topology, and/or interconnection requests that may occur over time that may result in different interconnection-related network upgrades to address the same interconnection-related need.[2400]

1132. The Commission stated that it believes that the proposed criteria the transmission provider must use to identify the interconnection-related transmission needs that should be considered in the regional transmission planning process will help to ensure that the associated interconnection-related network upgrades are likely to have produced benefits beyond those provided to the interconnection customers whose interconnection requests the interconnection-related network upgrades are needed to accommodate.[2401]

1133. To avoid shifting costs inappropriately from generators in the generator interconnection process to transmission customers through the regional transmission planning process, the Commission further proposed to limit the scope of interconnection-related transmission needs to be considered in the regional transmission planning process to those interconnection-related transmission needs not addressed by interconnection-related network upgrades memorialized in an executed generator interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission).[2402]

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[2400] *Id*.

[2401] *Id*. P 168.

[2402] *Id*. P 173.

**2. Comments**

1134. Multiple commenters generally support the NOPR proposal but express concerns about the eligibility criteria proposed in the NOPR and request modification.[2403] SDG&E states that the criteria defined in the NOPR strike an appropriate balance to cover many situations in which generation is needed, while also protecting ratepayers from unnecessary costs.[2404]

1135. Avangrid argues that, while the NOPR proposal has merit, the Commission should allow transmission providers to determine the most appropriate thresholds.[2405] SEIA asks the Commission to allow each transmission planning region to determine its own threshold, which may include lower voltage lines and substations.[2406] Indicated PJM TOs further argue that the proposed criteria may not be appropriate in all transmission planning regions.[2407]

1136. MISO argues that transmission planning regions should be able to develop their own cost and voltage criteria. MISO explains that it may be difficult to implement the requirement that interconnection-related network upgrades that qualify must "not

[2403] NARUC Initial Comments at 19-20; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments 31-33; SEIA Initial Comments at 14-15; Shell Initial Comments at 30; TAPS Initial Comments at 13; US DOE Initial Comments at 28.

[2404] SDG&E Initial Comments at 3.

[2405] Avangrid Initial Comments at 12.

[2406] SEIA Initial Comments at 15.

[2407] Indicated PJM TOs Initial Comments at 15-16.

currently be planned to be developed" in the interconnection process because in MISO's experience interconnection-related network upgrades shift from queue cycle to queue cycle as withdrawals occur, and as a result MISO suggests deleting this requirement. MISO opposes the requirement to identify any interconnection-related network upgrade that is identified in multiple generator interconnection studies as it would require the review and comparison of numerous studies to comply with no increased benefit.[2408]

1137. Multiple commenters that generally support the NOPR proposal suggest modification to the NOPR's proposed cost and voltage eligibility criteria. Pattern Energy suggests that the Commission should allow consideration of interconnection-related network upgrades that would meet either a voltage or a cost threshold because, for example, lower voltage lines that cost more than $30 million can often satisfy an interconnection need.[2409] Pattern Energy and Pine Gate argue that the Commission should lower the voltage threshold to 100 kV.[2410] Shell asks the Commission to lower the 200 kV threshold to 115 kV or to remove it entirely in favor of a cost threshold that is updated regularly based on inflation or some other Commission-approved indicator.[2411]

[2408] MISO Initial Comments at 45-46.

[2409] Pattern Energy Initial Comments at 28.

[2410] Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32.

[2411] Shell Initial Comments at 30.

1138. Pine Gate argues that the Commission should reduce the cost threshold to $10 million.[2412] SEIA argues that the cost threshold should be replaced with a $100,000/MW threshold.[2413] US DOE argues that a $30 million cost threshold may not be appropriate because some interconnection-related network upgrades that meet this eligibility factor may only benefit a limited number of interconnection customers. As an alternative, US DOE adds that the Commission should consider interconnection-related network upgrades "that would provide benefits beyond the local interconnection level or that would improve interconnection efficiencies across a wider geographic area and not substations, voltage support devices, or other local connection upgrades."[2414]

1139. Dominion states that the relatively low voltage and cost thresholds in the Commission's proposal invites interconnection customers to seek bigger investments than needed or select a location that increases the cost of interconnection.[2415] Dominion further argues that the number, size, or frequency of interconnection requests should not be used as a basis for planning transmission projects, because the process could be subject to gaming, where speculative interconnection requests could result in

[2412] Pine Gate Initial Comments at 32.

[2413] SEIA Initial Comments at 15.

[2414] US DOE Initial Comments at 28.

[2415] Dominion Initial Comments at 32.

transmission buildouts and spending that are not justified by actual grid needs or economics.[2416]

1140. Some commenters take issue with the NOPR's proposed criteria. Indicated PJM TOs argue that there is no record evidence to support the proposed 200 kV and $30 million cost threshold criteria.[2417] PJM states that few interconnection studies have identified the need for interconnection-related network upgrades in excess of $30 million.[2418] Illinois Commission contends that many projects in the interconnection queue are associated with interconnection-related network upgrades that meet the repeatedly-identified and 200 kV thresholds and that simply folding interconnection costs into transmission planning may expedite the queue at the expense of efficiency and cost-effectiveness.[2419] Indicated PJM TOs argue that limiting consideration to only generating facilities that have not yet signed (or had filed) an interconnection agreement will result in studying only uneconomic projects, which would run afoul of the cost causation principle.[2420]

1141. Interwest argues that the Commission should not require the identification of the interconnection-related network upgrade in two queue cycles over the five-year lookback

[2416] Dominion Reply Comments at 7-8.

[2417] Indicated PJM TOs Initial Comments at 15.

[2418] PJM Initial Comments at 88.

[2419] Illinois Commission Initial Comments at 8-9.

[2420] Indicated PJM TOs Initial Comments at 16.

period because such a requirement would limit the number of identified interconnection-related network upgrades that would trigger this newly proposed process.[2421] Pine Gate states that the Commission's look-back period should be at least the two immediately preceding interconnection queue cycles, or, where serial studies have been performed, during the preceding five years beginning at the time of the withdrawal of the first underlying interconnection request.[2422] Pine Gate argues that this revision will ensure that study results will be available for use in identifying interconnection-related network upgrades to evaluate.[2423] SEIA argues that once a transmission provider identifies the same interconnection-related network upgrade in two interconnection cycles, that line should be included in the next Long-Term Regional Transmission Planning update cycle even if five years have not passed since initial identification.[2424] Pattern Energy supports SEIA's requests.[2425]

1142. EEI and Eversource are unsure of the stage of the generator interconnection process at which a project would meet the proposed criteria.[2426] Eversource requests that

[2421] Interwest Initial Comments at 3, 11.

[2422] Pine Gate Initial Comments at 31.

[2423] *Id.*

[2424] SEIA Initial Comments at 15.

[2425] Pattern Energy Reply Comments at 10-11.

[2426] EEI Initial Comments at 17-18; Eversource Initial Comments at 24.

the Commission require transmission providers to specify the stage in the interconnection process that an interconnection-related network upgrade is identified.[2427]

1143. Pine Gate asks the Commission to combine the third and fourth criteria into one criterion: those interconnection-related network upgrades that are not developed or in development and not currently committed to be built under an interconnection service agreement or any related construction agreement.[2428]

1144. Some commenters argue that the Commission's proposed criteria create too simplistic of a method for determining which interconnection-related network upgrades should be evaluated in Long-Term Regional Transmission Planning.[2429] Pennsylvania Commission argues that, without a rigorous examination of why an interconnection application failed, there is no proof that there exists a need for building interconnection-related network upgrades as part of Long-Term Regional Transmission Planning.[2430] NARUC argues that the meaning of the term "multiple times" should be informed by a process that also examines the reasons why the previous interconnection requests were withdrawn, including generation developer land acquisition decisions or the identification

[2427] Eversource Initial Comments at 24.

[2428] Pine Gate Initial Comments at 32-33.

[2429] NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2430] Pennsylvania Commission Initial Comments at 8.

of more economic transmission design alternatives.[2431] Vistra takes issue with the fact that the Commission does not distinguish between situations when developers simply sought to develop in an uneconomic area versus when a more efficient or cost-effective transmission project would have been identified as part of the regional transmission planning process.[2432]

### 3. Commission Determination

1145. We adopt the NOPR proposal, with modification, to require that, for a regional transmission facility to address an interconnection-related transmission need to qualify for evaluation through the regional transmission planning process for selection under this reform, any interconnection-related network upgrade identified to meet that interconnection-related transmission need must meet both the proposed voltage *and* cost criteria. Thus, we require transmission providers to evaluate for selection in their existing Order No 1000 regional transmission planning processes regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions

[2431] NARUC Initial Comments at 19.

[2432] Vistra Initial Comments at 20.

proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions); (2) an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million; (3) such interconnection-related network upgrade(s) have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the network upgrade(s) has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.

1146. We find it necessary to establish these criteria to limit the scope of the requirement for transmission providers to evaluate regional transmission facilities to address interconnection-related transmission needs in their regional transmission planning processes to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. We find that each of the four criteria are necessary to identify the appropriate set of interconnection-related transmission needs. Moreover, we find that the modification to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need must satisfy both the voltage and cost

thresholds better limits the scope of this reform by ensuring that any regional transmission facilities evaluated to address such interconnection-related transmission needs are more likely to provide widespread benefits to transmission customers.[2433]

1147. We further find that these criteria strike a reasonable balance between precision and workability. Our reforms here are intended to ensure that transmission providers must identify interconnection-related transmission needs for evaluation in their regional transmission planning processes that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Requiring in-depth qualitative analysis of individual interconnection requests, including consideration of why they were withdrawn, as some commenters suggest, would undermine these goals. Furthermore, these criteria simply determine whether transmission providers must *evaluate* regional transmission facilities to address any given

[2433] The Commission has previously found that network upgrades can benefit all transmission customers. *See* Order No. 2003, 104 FERC ¶ 61,103 at PP 21, 65 (stating "[m]ost improvements to the Transmission System, including Network Upgrades, benefit all transmission customers" and "the definition of Network Upgrade [includes] the phrase 'at or beyond the Point of Interconnection,' . . . [f]acilities beyond the Point of Interconnection are part of the Transmission Provider's Transmission System and benefit all users"); Order No. 2003-A, 106 FERC ¶ 61,220 at P 584 (citing *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 543-544 (D.C. Cir. 2003)). The Commission has also previously found, and the record demonstrates, that higher-voltage transmission facilities are more likely to provide widespread benefits to transmission customers. *See* NOPR, 179 FERC ¶ 61,028 at PP 32 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486), 168; *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 73 (2010); *Midwest Indep. Trans. Sys. Operator, Inc.*, 129 FERC ¶ 61,060, at P 8 (2009). *See also, e.g.*, CAISO ANOPR Comments at 54; Invenergy Initial Comments at 14; Southeast PIOs Initial Comments at 24.

interconnection-related transmission need for potential selection; transmission providers may still separately assess whether any particular regional transmission facility qualifies for selection in the relevant existing regional transmission planning process(es). Therefore, we disagree with commenters that argue that the proposed criteria create too simplistic a method for determining which interconnection-related transmission needs should be evaluated in regional transmission planning and cost allocation processes.[2434]

1148. We decline to allow transmission providers to determine appropriate qualifying criteria,[2435] because the record supports our adoption of the qualifying criteria established by this rule. As described directly above, we find that these specific criteria ensure that the interconnection-related transmission needs that we require transmission providers to evaluate through their regional transmission planning processes are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Furthermore, transmission providers retain the flexibility to determine whether to select a regional transmission facility, and these criteria will simply determine whether transmission providers, pursuant to this final rule, must evaluate interconnection-related transmission needs in the Order No. 1000 regional transmission planning and cost allocation processes.

[2434] *See* NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2435] *See* Avangrid Initial Comments at 12; MISO Initial Comments at 45-46; SEIA Initial Comments at 15.

1149. We also disagree with Indicated PJM TOs' argument that the proposed criteria may not be appropriate in all transmission planning regions because of the differences in scales, topology, and economics.[2436] While each transmission planning region is unique, we find that the criteria that we establish here are broad enough to capture interconnection-related network upgrades that are likely to produce benefits beyond the interconnection customer across transmission planning regions despite their differences. Furthermore, as stated above, transmission providers in each transmission planning region retain the flexibility to select regional transmission facilities, and the criteria that we adopt here do not mandate that the transmission providers in any transmission planning region select any particular regional transmission facilities to address interconnection-related transmission needs.

1150. Additionally, we find that the qualifying criteria that we establish here that an interconnection-related need must be repeated twice and meet both voltage and cost thresholds are just and reasonable. We disagree with commenters that argue for the adoption of different criteria or for the elimination of one or both criteria.[2437] We find that the purpose of the criteria established here is precisely to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration in the existing Order No. 1000 regional transmission

[2436] *See* Indicated PJM TOs Initial Comments at 15-16.

[2437] *See* Dominion Initial Comments at 32; Indicated PJM TOs Initial Comments at 15; Interwest Initial Comments at 3, 11; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; Shell Initial Comments at 30.

planning and cost allocation processes. The requirement of the repeat identification of an interconnection-related need in at least two interconnection queue cycles during the preceding five years criterion provides an important limit on the extent to which evaluation is required. Namely, this and the other criteria together indicate that it is likely that the relevant interconnection-related transmission needs will persist but were not resolved because the high associated interconnection-related network upgrade costs drove the withdrawal of the underlying interconnection requests. The repeat identification of interconnection-related network upgrades driven by a common interconnection-related transmission need also indicates that the constraint that the interconnection-related network upgrades were identified to address is not unique to a single interconnection request at a single point in time. Additionally, relaxing this repeat identification requirement may be overburdensome to transmission providers because it could increase the number of interconnection-related transmission needs that transmission providers must evaluate in their regional transmission planning and cost allocation processes.

1151. We find that it is necessary to establish a cost threshold criterion that is stringent enough to capture those interconnection-related network upgrades that are likely to have caused the underlying interconnection requests to withdraw. Additionally, we find that it is necessary to establish a voltage criterion that is high enough so that any regional transmission facility evaluated to address the underlying interconnection-related transmission need(s) is likely to produce benefits that extend beyond the interconnection customer. We further believe that these criteria are important to limit the number of

interconnection-related transmission needs that transmission providers must evaluate to a practical set so that transmission providers do not have to evaluate numerous regional transmission facilities to address those needs that are unlikely to be selected.

1152. Consequently, the modification adopted here to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfies both the voltage and cost criteria will achieve these results. In particular, this modification will prevent transmission providers from evaluating interconnection-related transmission needs associated with interconnection-related network upgrades that are either above 200 kV but lower-cost or cost more than $30 million but are less than 200 kV, which means that they are less likely to provide more widespread benefits to transmission customers.

1153. The change to the voltage and cost criteria also address commenters' concerns.[2438] For example, as US DOE notes, in some instances, network upgrades that cost $30 million or more may only benefit a limited number of interconnection customers.[2439] Consequently, the change that we adopt to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfy both the voltage and cost criteria will more narrowly define a set of interconnection-

[2438] Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; US DOE Initial Comments at 28.

[2439] US DOE Initial Comments at 28.

related transmission needs that the transmission provider must evaluate in the regional transmission planning process.

1154. The record supports a 200 kV threshold. For example, as noted in the NOPR, the Commission has previously found CAISO's use of a 200 kV threshold was just and reasonable for determining eligibility for evaluating interconnection-related network upgrades in the regional transmission planning process. The Commission found that CAISO's proposed threshold "strikes a reasonable balance between . . . accommodating the generators' need to interconnect . . . in a timely manner, and the benefits that can flow from evaluating the larger projects in the comprehensive transmission planning process."[2440] As such, we continue to believe that a 200 kV voltage threshold is sufficiently high such that the interconnection-related network upgrades can more reasonably be expected to produce regional benefits to transmission customers than lower-voltage transmission facilities.

1155. We also continue to believe that $30 million is an appropriate threshold for the cost criteria related to this requirement. We find that the $30 million threshold is consistent with the record established in this proceeding regarding how the costs of interconnection-related network upgrades lead to interconnection customers withdrawing from the queue.[2441] A lower cost criterion may require transmission providers to evaluate

[2440] *Cal Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,224, at P 103 (2010); *see also* NOPR, 179 FERC ¶ 61,028 at P 165 n.300 & P 172 n.302.

[2441] NOPR, 179 FERC ¶ 61,028 at P 172 n.303.

in the regional transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades that have a greater likelihood to be affordable for interconnection customers. Additionally, we are concerned that the $/kW cost threshold proposed by SEIA may not capture interconnection-related network upgrades that are more likely to provide regional benefits to transmission customers beyond the interconnection customer. Further, transmission providers may face practical challenges in identifying the specific kW size corresponding to the interconnection-related transmission need associated with an interconnection-related network upgrade because the same interconnection-related network upgrade can be identified as needed for multiple interconnection requests (or groups of requests) of different kW sizes.

1156. Additionally, we reiterate that the criteria adopted herein do not require transmission providers to select any particular regional transmission facility to address interconnection-related transmission needs. Instead, we require transmission providers to simply evaluate regional transmission facilities to address interconnection-related transmission needs that meet these criteria for potential selection, recognizing that transmission providers may ultimately determine through their regional transmission planning processes that such regional transmission facilities are not eligible or sufficiently beneficial to be selected.

1157. We disagree with Indicated PJM TOs' argument that limiting evaluation to exclude interconnection-related network upgrades identified in generator interconnection requests that have executed (or requested to be filed unexecuted) an interconnection

agreement will result in studying only uneconomic projects.[2442] This criterion ensures that transmission providers are not required to evaluate in their regional transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades for which an interconnection customer has already agreed to pay.[2443] Furthermore, in response to MISO's suggestion to delete this limiting aspect, we clarify that this criterion excludes instances in which an interconnection-related network upgrade is identified in an executed generator interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission),[2444] not instances where an interconnection-related network upgrade that meets the criteria in this section is identified as needed for an interconnection request that has not proceeded to the generator interconnection agreement phase of the interconnection study process.

1158. The criterion requiring that interconnection-related transmission needs are identified in at least two interconnection queue cycles during the preceding five years will help to ensure that an interconnection-related transmission need is likely to persist and is not unique to a single interconnection request before requiring transmission providers to evaluate a regional transmission facility to address that need for potential

[2442] Indicated PJM TOs Initial Comments at 16.

[2443] NOPR, 179 FERC ¶ 61,028 at P 173.

[2444] MISO Initial Comments at 46.

selection.[2445] We recognize that, in limited circumstances, it is possible that there may be only one interconnection queue cycle during a five-year period. We clarify that if more than five years pass between interconnection queue cycles, then this criterion should be read to include the interconnection queue cycle that immediately preceded the current interconnection queue where the interconnection-related transmission need is identified.[2446]

1159. We adopt the NOPR proposal that the initial five-year period will begin five calendar years prior to the effective date of the Commission-accepted tariff provisions proposed to comply with this final rule. Thus, transmission providers must evaluate an interconnection-related transmission need that has been previously identified multiple times within the five years prior to the effective date of the Commission-accepted tariff provisions, but never been resolved due to the withdrawal of the underlying interconnection request(s). This assumes that the other qualifying criteria are met for the interconnection-related transmission need. The evaluation for selection of regional transmission facilities that address certain identified interconnection-related transmission needs must occur in the first Order No. 1000 regional transmission planning and cost allocation processes cycle that commences after the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions.

[2445] Pattern Energy Reply Comments at 10-11; Pine Gate Initial Comments at 31; SEIA Initial Comments at 14-15.

[2446] *See* Pine Gate Initial Comments at 31.

1160. Additionally, we clarify that if there are no queue cycles in the preceding five-year period because the transmission provider uses a first-come, first-served serial interconnection process, then this criterion will be met based on the identification of interconnection-related transmission needs in individual interconnection studies. That is, if the interconnection-related transmission need is identified in at least two individual interconnection studies during the preceding five-year period for interconnection customers that subsequently withdrew from the interconnection queue, then this criterion is met. We further clarify, as discussed immediately above, that if a transmission provider identifies the same interconnection-related transmission need in two interconnection queue cycles during a five-year period or less, the transmission provider must evaluate that interconnection-related transmission need even if five years have not yet passed since the initial identification.[2447]

1161. In response to Eversource's request that we require transmission providers to specify the stage in the generator interconnection process that an interconnection-related network upgrade is identified,[2448] we clarify that the criterion discussed herein applies no matter the stage in which the upgrades are identified, because we are concerned with interconnection-related transmission needs going unaddressed due to withdrawals regardless of the stage of the generator interconnection process.

[2447] *See* Pattern Energy Reply Comments at 10-11; SEIA Initial Comments 15.

[2448] *See* EEI Initial Comments at 17-18; Eversource Initial Comments at 24.

1162. Finally, we decline to combine the third and fourth criteria into one criterion as Pine Gate suggests, because we find that it is unnecessary.[2449] This reform creates a process for the evaluation of interconnection-related transmission needs in regional transmission planning and cost allocation processes if those needs have not been addressed and are unlikely to be addressed through the development of an interconnection-related network upgrade in the generator interconnection process. The purpose of the third criterion is to limit the reform to those interconnection-related transmission needs where the associated interconnection requests have been withdrawn; that is, this criterion requires the repeat withdrawal. The fourth criterion, that the interconnection-related network upgrade not be identified in a generator interconnection agreement, ensures that the interconnection-related network upgrade has not been developed and is not planned to be developed because a generator interconnection agreement memorializes the transmission owner's obligation to develop an identified interconnection-related network upgrade.[2450]

[2449] *See* Pine Gate Initial Comments at 32-33.

[2450] *See Pro forma* LGIA art. 11.3 ("Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades . . . described in Appendix B.").

## V. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

### A. General Proposal

#### 1. NOPR Proposal

1163. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to consider two specific technologies more fully in regional transmission planning and cost allocation processes: dynamic line ratings and advanced power flow control devices. The Commission recognized that selecting transmission facilities that incorporate such technologies serving a transmission function in the regional transmission plan for purposes of cost allocation could be more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies.[2451]

1164. More specifically, the Commission proposed to require transmission providers in each transmission planning region to consider for each identified regional transmission need whether selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices would be more efficient or cost-effective than selecting transmission facilities that do not incorporate these technologies. The Commission proposed that such consideration should first address whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-

[2451] NOPR, 179 FERC ¶ 61,028 at PP 272-273.

effectively than other transmission facilities that are being considered for potential selection. Second, the Commission proposed that, when evaluating transmission facilities for potential selection, transmission providers in each transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective than potential regional transmission facilities that do not incorporate such technologies. The Commission proposed to apply this requirement in all aspects of the regional transmission planning processes, including the existing regional transmission planning process for near-term regional transmission needs and Long-Term Regional Transmission Planning. As is the case for any other transmission facility selected, the Commission proposed that the costs to incorporate dynamic line ratings or advanced power flow control devices selected, whether as an addition to an existing transmission facility or as part of a new regional transmission facility, be allocated using the applicable regional cost allocation method.[2452]

1165. The Commission noted that, as required by Order No. 1000, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected.[2453] The Commission proposed to extend this requirement such that transmission providers must

[2452] *Id.* P 274.

[2453] *Id.* P 275 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328; Order No. 1000-A, 139 FERC ¶ 61,132 at P 267).

ensure that the determination of whether to incorporate dynamic line ratings and advanced power flow control devices is sufficiently detailed for stakeholders to understand why they were or were not incorporated into selected regional transmission facilities.[2454]

1166. The Commission also sought comment on whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if dynamic line ratings are identified as a more efficient or cost-effective transmission facility.[2455]

### 2. Comments on General Proposal

1167. Many commenters, including technology developers, environmental advocates, ratepayer advocates, and independent market monitors, support the NOPR proposal.[2456]

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[2454] *Id.*

[2455] *Id.* P 277.

[2456] ACEG Initial Comments at 31; ACORE Initial Comments at 15-16; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 4; AEE Initial Comments at 27-28; CARE Coalition Initial Comments at 2-3; Certain TDUs Reply Comments at 7-9; Clean Energy Associations Initial Comments at 28; Clean Energy Associations Reply Comments at 7-8; Conservative Energy Network Supplemental Comments at 1-2; Conservatives for Clean Energy – Florida Supplemental Comments at 1-2; Conservatives for Clean Energy – South Carolina Supplemental Comments at 1; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36; DC and MD Offices of People's Counsel Reply Comments at 8-9; Evergreen Action Initial Comments at 4; Hannon Armstrong Reply Comments at 2; Illinois Commission Initial Comments at 11-13; Indicated US Senators and Representatives Initial Comments at 2; Joint Consumer Advocates Initial Comments at 13; Massachusetts Attorney General Initial Comments at 16-18; Michigan Conservative Energy Forum Supplemental Comments at 1; Michigan State Entities Initial Comments at 10; NARUC Initial Comments at 35; NASEO Initial Comments at 6; NASUCA Initial Comments at 7-8; NESCOE Initial Comments at 53;

For example, many commenters state that these technologies provide significant annual cost savings[2457] or affect both the capital investment and consumer benefits of cost allocation.[2458] Additionally, some federal legislators support the NOPR proposal.[2459] CARE Coalition asserts that the Commission should use all available tools and technologies to increase the efficiency and capacity of the transmission network.[2460] ELCON states that transmission planning processes should ascertain whether current infrastructure can be improved before reviewing costlier or slower options like greenfield

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Nevada Commission Initial Comments at 13; Ohio Conservative Energy Forum Supplemental Comments at 1; Pennsylvania Commission Initial Comments at 11; PIOs Initial Comments at 22; PJM Market Monitor Initial Comments at 6; Potomac Economics Initial Comments at 5; Prysmian Initial Comments at 1; Smart Wires Initial Comments at 1; SPP Market Monitor Initial Comments at 9; US DOE Initial Comments at 36-37; WATT Coalition Initial Comments at 2; WATT Coalition Supplemental Comments at 2-3; Western Way Colorado Supplemental Comments at 1-2; Western Way Nevada Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[2457] Cross Sector Representatives Supplemental Comments at 1; WATT Coalition Supplemental Comments at 2-3.

[2458] Conservative Energy Network Supplemental Comments at 1-2; Conservatives for Clean Energy – Florida Supplemental Comments at 1-2; Conservatives for Clean Energy – South Carolina Supplemental Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum at 1; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[2459] Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 3.

[2460] CARE Coalition Initial Comments at 3.

transmission, and greater weight should be given to those transmission projects that incorporate grid enhancing technologies.[2461] Certain TDUs state that they participate actively in the MISO transmission planning process, and that they have observed that grid enhancing technologies and other non-transmission alternatives do not receive the attention that they deserve.[2462] AEE contends that the Commission has an obligation to promote the adoption of alternative transmission technologies, as directed by Congress in the Energy Policy Act of 2005, and AEE states that the Commission has not made explicit efforts to implement this mandate beyond offering rate incentives for alternative transmission technologies.[2463]

1168. Industrial Customers assert that requiring dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies will require transmission utilities to deploy capital where it is needed most to maintain reliability, which will reduce transmission costs to consumers because dynamic line ratings extend the useful life of existing transmission infrastructure and optimize existing grid capabilities.[2464] ENGIE claims that deploying grid enhancing technologies could help to contain costs and support efficient, advanced projects.[2465] Invenergy argues that, even if there may be

[2461] ELCON Initial Comments at 5, 20.

[2462] Certain TDUs Reply Comments at 8.

[2463] AEE Initial Comments at 29 (citing 42 U.S.C. 16422).

[2464] Industrial Customers Reply Comments at 13-14.

[2465] ENGIE Reply Comments at 3-4.

instances where dynamic line ratings and advanced power flow control devices do not provide the best option with respect to cost, transmission providers should still undertake the analysis.[2466] Potomac Economics observes that incorporating grid enhancing technologies in the transmission planning process will help ensure that transmission owners do not incur inefficient transmission upgrade costs to mitigate congestion that can be reduced more cost-effectively by grid enhancing technologies.[2467]

1169. Individual state governmental entities as well as NASEO, NASUCA, and NESCOE emphasize the importance of considering more efficient or cost-effective alternatives.[2468] Some state commissions and US DOE cite the benefits of cost containment for customers.[2469] DC and MD Offices of People's Counsel and Clean Energy Associations assert that grid enhancing technologies provide value beyond lowering transmission costs, as they can be deployed quickly, are modular, have low environmental and geographic footprints, and can be developed at low risk.[2470] NARUC

[2466] Invenergy Reply Comments at 17.

[2467] Potomac Economics Initial Comments at 5.

[2468] Massachusetts Attorney General Initial Comments at 16-18; Michigan State Entities Initial Comments at 10 (citing Institute for Policy Integrity ANOPR Reply Comments at 8); NASEO Initial Comments at 6; NASUCA Initial Comments at 7-8; NESCOE Initial Comments at 53.

[2469] Illinois Commission Initial Comments at 11-13; NARUC Initial Comments at 35-36; Nevada Commission Initial Comments at 13; Pennsylvania Commission Initial Comments at 11; US DOE Initial Comments at 36-37.

[2470] Clean Energy Associations Initial Comments at 27; DC and MD Offices of People's Counsel Reply Comments at 8.

asserts that an effective transmission planning process should maximize the use of existing transmission and allow for building new transmission only where necessary or economic.[2471] Indicated US Senators and Representatives support the use of advanced transmission technologies to increase the efficiency and resilience of the electric grid.[2472]

1170. Many commenters support the consideration of alternative transmission technologies in transmission planning. For example, Certain TDUs argue that the Commission must protect ratepayers and consider all alternatives to ensure safe, reliable, and cost-effective transmission solutions, including the use of alternative transmission technologies.[2473] Invenergy avers that there may be instances where better using these technologies may require certain foundational investments (e.g., appropriate software), but that only reinforces the need to establish a requirement to drive change.[2474] Industrial Customers state that transmission providers should have to consider grid enhancing technologies whenever additional transmission investment is the alternative because the cost of installing them will almost always be nominal compared to the benefits of reduced congestion, lower energy and capacity costs, and reduced need for increases in transmission system capability.[2475]

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[2471] Industrial Customers Reply Comments at 12; NARUC Initial Comments at 35.

[2472] Indicated US Senators and Representatives Initial Comments at 2.

[2473] Certain TDUs Reply Comments at 8.

[2474] Invenergy Reply Comments at 17.

[2475] Industrial Customers Reply Comments at 16.

1171. WATT Coalition asserts that alternative transmission technologies and new transmission capacity are complementary.[2476] WATT Coalition and Industrial Customers further assert that there is substantial value in considering dynamic line ratings in Long-Term Regional Transmission Planning because they can provide data to strengthen assumptions made in the planning process.[2477] Specifically, WATT Coalition explains that historical data sets of dynamic transmission line ratings can be analyzed to create probabilistic line ratings on a seasonal, monthly, or more granular level to inform the transmission planning process, helping to maximize its efficiency.[2478] Finally, WATT Coalition states that the use of forecasted ambient-adjusted ratings (Ambient Adjusted Ratings) demonstrates that more granular data inputs can and should be captured to increase the value of new transmission investment, as well as increased reliability and market efficiency.[2479]

1172. Invenergy states that, if there are concerns about the burden associated with evaluating alternative transmission technologies, the Commission could adopt a

[2476] WATT Coalition Reply Comments at 2.

[2477] Industrial Customers Reply Comments at 18; WATT Coalition Reply Comments at 1-3 (citing Appendix B of its Reply Comments).

[2478] WATT Coalition Reply Comments Appendix B at 12. For example, WATT Coalition reports that ERCOT uses historical dynamic line rating data in its regional transmission plan. *Id.* (citing ERCOT 2021 Regional Transmission Plan Report, section 1.2, https://www.ercot.com/files/docs/2021/12/23/2021_Regional_Transmission_Plan_Report_Public.zip).

[2479] *Id.* Appendix B at 13.

reasonable threshold under which transmission providers are required to consider whether dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies may be more efficient or cost-effective. For example, Invenergy suggests that, if an overload is identified and the relevant facilities are overloaded by 20% or less, the transmission provider should be required to consider grid enhancing technologies as a solution. Invenergy urges the Commission to reject calls to make the proposal an optional process, noting that transmission providers can already consider these technologies, but many do not.[2480]

1173. Some commenters express partial support for the NOPR proposal but raise concerns about certain aspects.[2481] California Water supports consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning but recommends that any final rule clarify that such technologies should be adopted only if they are considered in the regional transmission planning process as the Commission proposes, serve the purpose of cost containment, and are found to be efficient and cost-effective.[2482] TAPS states that while it supports the implementation of grid enhancing technologies, they may be better suited for

[2480] Invenergy Reply Comments at 16-17.

[2481] CAISO Initial Comments at 37-39, California Water Initial Comments at 20; ENGIE Initial Comments at 6; Invenergy Initial Comments at 14-16; Ohio Consumers Initial Comments at 32-33; Pattern Energy Initial Comments at 29; SEIA Initial Comments at 21-22; SPP Initial Comments at 25-26, TAPS Initial Comments at 4, 21-22.

[2482] California Water Initial Comments at 20.

consideration on a shorter regional transmission planning horizon.[2483] While Pattern Energy supports the consideration of grid enhancing technologies in Long-Term Regional Transmission Planning, it similarly notes that dynamic line ratings and advanced power flow control devices are shorter-term transmission solutions—helping to "squeeze more" out of the infrastructure that is operating or planned to be constructed.[2484]

1174. While ENGIE supports the Commission's proposal to require the evaluation and deployment of dynamic line ratings and advanced power flow control devices where beneficial in Long-Term Regional Transmission Planning, it notes that the operational data used by such devices are not yet easily incorporated into the transmission planning framework.[2485] Similarly, SEIA and Invenergy raise concerns that utilities struggle to consider, evaluate, and select these technologies as transmission solutions due to a lack of information about how they might be integrated into the transmission planning process.[2486]

1175. Finally, National Grid generally supports the notion that transmission providers should consider whether and how alternative transmission technologies can be incorporated into transmission planning and states that such technologies, in certain instances, may offer a more efficient or cost-effective alternative to other regional

[2483] TAPS Initial Comments at 4, 21-22.

[2484] Pattern Energy Initial Comments at 29.

[2485] ENGIE Initial Comments at 6.

[2486] Invenergy Initial Comments at 14-16; SEIA Initial Comments at 21-22.

transmission facilities.[2487] However, National Grid states that, if the Commission adopts in a final rule the requirement to fully consider dynamic line ratings and advanced power flow control devices, it should explain how it expects RTOs/ISOs to implement the first step of the consideration process articulated in the NOPR, i.e., that the alternative transmission technologies being incorporated into existing transmission facilities "could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities."[2488] According to National Grid, such a requirement would exceed the RTO/ISO's authority as the independent administrator of the competitive solicitation process.[2489]

1176. Many commenters oppose the NOPR proposal.[2490] Some commenters warn the Commission of the potential reliability and operational impacts of the widespread use of

[2487] National Grid Initial Comments at 21.

[2488] *Id.*at 23 (quoting NOPR, 179 FERC ¶ 61,028 at P 274).

[2489] *Id.*

[2490] AEP Initial Comments at 33; Ameren Initial Comments at 23-24; APPA Initial Comments at 37; ATC Initial Comments at 7-8; Avangrid Initial Comments at 31; DATA Initial Comments at 17; Dominion Initial Comments at 40; Duke Initial Comments at 29-32; EEI Initial Comments at 20-22; Entergy Initial Comments at 26-28; Eversource Initial Comments at 27-28; Exelon Initial Comments at 18-23; Georgia Commission Initial Comments at 7-8; Idaho Power Initial Comments at 9; Indicated PJM TOs Initial Comments at 19-20; ITC Initial Comments at 26-28; ITC Reply Comments at 27; LADWP Initial Comments at 5; Large Public Power Initial Comments at 31-34; MISO TOs Initial Comments at 23-24; Mississippi Commission Reply Comments at 8; New York TOs Initial Comments at 22-23; NRECA Initial Comments at 52; NYISO Initial Comments at 45, 47; OMS Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15-16; PJM Initial Comments at 105-109; PPL Initial Comments at 22-23; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36-37; US

dynamic line ratings and advanced power flow control devices.[2491] APPA asserts that transmission dynamic line ratings and advanced power flow control devices should not be required until the industry has further experience with Ambient-Adjusted Ratings deployment.[2492] Exelon asserts that transmission providers already consider grid enhancing technologies and notes that, in many instances, the selection and deployment of grid enhancing technologies are fundamentally incompatible with the competitive transmission requirements in Order No. 1000, particularly in the context of development of new transmission facilities, where grid enhancing technologies are unlikely to be the lower cost solution, and may be considerably more expensive than traditional transmission technologies.[2493]

1177. Some commenters argue that further support is needed to justify any mandate to consider alternative transmission technologies in transmission planning.[2494] Kansas Commission asserts that any new requirements should be based on a data-driven, robust analysis demonstrating ratepayer benefits; it also cautions against using such technologies as a short-term fix.[2495] ATC states that the Commission should develop a record of the

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Chamber of Commerce Initial Comments at 9.

[2491] Duke Initial Comments at 31-32; Entergy Initial Comments at 27-28; MISO Initial Comments at 59-60.

[2492] APPA Initial Comments at 5.

[2493] Exelon Initial Comments at 21.

[2494] ATC Reply Comments at 3; Kansas Commission Initial Comments at 19-20.

[2495] Kansas Commission Initial Comments at 19-20.

costs, risks, and potential impacts of widespread implementation of dynamic line ratings before mandating further action.[2496]

1178. Some commenters raise concerns about the costs of alternative transmission technologies. Mississippi Commission argues that mandating the use of technologies without considering their cost is not just and reasonable.[2497] ATC asserts that the costs of implementing dynamic line ratings system wide would not be nominal.[2498] US Chamber of Commerce asserts that dynamic line ratings are not a way to obtain "free" transmission capacity because there are costs associated with monitoring the ratings.[2499]

1179. Other commenters argue that the Commission should favor flexibility and not mandate that dynamic line ratings and advanced power flow control devices be considered.[2500] Georgia Commission states that it is reasonable for the Commission to encourage, rather than require, consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning.[2501] LADWP

[2496] ATC Reply Comments at 3.

[2497] Mississippi Commission Reply Comments at 8.

[2498] ATC Reply Comments at 3 (citing Pattern Energy Initial Comments at 30; Pine Gate Initial Comments at 40-41).

[2499] US Chamber of Commerce Initial Comments at 9.

[2500] Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7-8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

[2501] Georgia Commission Initial Comments at 7.

suggests that instead of mandating consideration of specific technologies that become obsolete, the Commission should require transmission providers to use Good Utility Practice to identify and use technologies that maximize the use of transmission assets in order to minimize impacts to ratepayers and the public.[2502]

1180. Similarly, National Grid argues that the Commission should not favor the deployment of the two proposed technologies over more efficient or cost-effective transmission facilities, and that focusing on specific technologies is likely to stifle innovation and will not lead to the identification of the more efficient or cost-effective transmission facilities.[2503] ATC disagrees with commenters that state that utilities are reluctant to implement these technologies,[2504] noting that it advocates for and uses advanced power flow control devices and other advanced technologies on its system.[2505] However, ATC describes widespread dynamic line rating deployment as costly.[2506]

1181. Other commenters urge the Commission to complete its consideration of the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings[2507] and/or wait for transmission providers to comply with Order No. 881[2508] before

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[2502] LADWP Initial Comments at 5.

[2503] National Grid Initial Comments at 22-23.

[2504] ATC Reply Comments at 2 (citing Invenergy Initial Comments at 15).

[2505] *Id.* (citing ATC Initial Comments at 7).

[2506] *Id.* at 3.

[2507] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (2022).

[2508] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179

implementing the NOPR proposal on dynamic line ratings.[2509] Large Public Power states that the Commission appears to sidestep the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings, especially the technical and cybersecurity-related concerns in that docket.[2510] MISO TOs state that imposing a mandate in this proceeding would complicate the issue.[2511] ATC argues that a more prudent course of action would be to gain experience with Ambient-Adjusted Ratings before moving on to consideration of the use of dynamic line ratings.[2512] ITC asserts that dynamic line ratings and advanced power flow control devices should be implemented on an operational basis through existing Commission proceedings addressing such technologies.[2513]

1182. Several commenters specifically support the NOPR proposal of requiring consideration of both: (1) whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other transmission facilities that are being considered for potential selection; and (2) whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional

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(2021).

[2509] ATC Reply Comments at 4-5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32-33; MISO TOs Initial Comments at 23-24.

[2510] Large Public Power Initial Comments at 32.

[2511] MISO TOs Initial Comments at 23.

[2512] ATC Initial Comments at 10.

[2513] ITC Reply Comments at 27.

transmission facility would be more efficient or cost-effective than those without incorporating such technologies.[2514] Ohio Consumers emphasize the importance of considering dynamic line ratings and advanced power flow control devices for both proposed and existing projects, noting that the goal of using these technologies is to lower overall costs of new transmission for consumers, and citing to a DOE study that found that these technologies can defer or reduce the need for significant investment in new infrastructure projects, and increase the use of renewables by maximizing the capacity of current infrastructure.[2515]

1183. Others oppose the consideration of alternative transmission technologies on new transmission facilities.[2516] CAISO contends that a requirement to consider whether to incorporate dynamic line ratings and advanced power flow control devices as part of every new regional transmission facility identified to meet a reliability need would create more work without yielding significant benefits because incorporating such measures

[2514] ACORE Initial Comments at 15; Clean Energy Associations Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 36; Industrial Customers Initial Comments at 32-34; Michigan State Entities Initial Comments at 11; NASEO Initial Comments at 6; Ohio Consumers Initial Comments at 34; State Agencies Initial Comments at 17-18.

[2515] Ohio Consumers Initial Comments at 32-34 (citing US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact* (Feb. 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf).

[2516] CAISO Initial Comments at 6; LADWP Initial Comments at 5.

would not alter the scope of the underlying transmission facilities that are necessary to meet the reliability need.[2517] LADWP states that identification of specific technologies in a rulemaking seems inappropriate and asserts a transmission line that is not yet built has no operating history, and it should therefore be at the discretion of the transmission planner to consider and implement dynamic line ratings, as it would slow down the design and construction of the transmission line.[2518] Exelon states that, particularly in the context of new transmission facilities, grid enhancing technologies are very unlikely to be the lower cost solution relative to traditional transmission technologies, and for many technologies, they should be expected to be considerably more expensive than traditional transmission technologies (notwithstanding any additional benefits they may offer).[2519]

1184. Clean Energy Associations, Industrial Customers, and WATT Coalition support the implementation of a requirement for non-RTO/ISO regions to update their energy management systems if dynamic line ratings are identified as a more efficient or cost-effective transmission facility selected.[2520] ELCON agrees, asserting that the Commission's requirement for dynamic line ratings and advanced power flow control

[2517] CAISO Initial Comments at 6. CAISO, however, supports considering these technologies in connection with new transmission facilities intended to meet economic or public policy needs. *Id.*

[2518] LADWP Initial Comments at 5.

[2519] Exelon Initial Comments at 21-22.

[2520] Clean Energy Associations Initial Comments at 28; Industrial Customers Initial Comments at 32-33; Industrial Customers Reply Comments at 11; WATT Coalition Initial Comments at 7.

devices should apply to all Commission-jurisdictional transmission utilities, regardless of whether they are RTOs/ISOs.[2521] WATT Coalition adds that all transmission providers should be required to upgrade their energy management systems and keep them consistent across all transmission providers to accommodate the latest technologies.[2522] WATT Coalition further states that advanced power flow control devices and topology optimization do not require modifications to existing energy management systems, but that the implementation of such technologies would benefit from the increased flexibility of dynamic line rating-enabled energy management systems.[2523]

1185. Pattern Energy states that energy management systems and other equipment will need upgrades to integrate readouts from the dynamic line ratings equipment to minimize operator intervention and enhance operational awareness. Pattern Energy surmises, however, that any upgrades necessitated by a final rule in this proceeding may be nominal given that dynamic line ratings and advanced power flow control devices should already be readily integrated with upgrades to energy management systems needed to comply with Order No. 881.[2524]

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[2521] ELCON Initial Comments at 21.

[2522] WATT Coalition Initial Comments at 7.

[2523] *Id.*

[2524] Pattern Energy Initial Comments at 30 (citing Order No. 881, 177 FERC ¶ 61,179).

1186. Some commenters suggest alternative approaches to incorporating alternative transmission technologies into the transmission system. Vistra asserts that the Commission should modify the NOPR proposal to require: (1) the long-term transmission planning evaluation to include a generation capacity expansion scenario that incorporates the potential for enhanced capability through new market services; (2) early input during the transmission planning cycle from independent market monitors and stakeholders on market improvements that could enhance grid operations; and (3) all solicitations for long-term solutions to equally consider non-transmissions solutions that may include generation, technology, or market design changes that could more efficiently or cost-effectively address a need that otherwise would require construction or modification of transmission facilities.[2525]

1187. Some commenters request that the Commission establish more prescriptive requirements regarding the evaluation of the alternative transmission technologies than those proposed in the NOPR. Invenergy asserts that the NOPR proposal should be expanded to include other technologies and require transmission providers to select alternative transmission technologies when they provide the most efficient option.[2526]

1188. WATT Coalition urges the Commission to include an operational planning timeframe for topology optimization, dynamic line ratings, and modular advanced power

[2525] Vistra Initial Comments at 32.

[2526] Invenergy Reply Comments at 16 (citing Invenergy Initial Comments at 14-17).

flow control devices, which can all be deployed quickly. WATT Coalition states that the Commission could require consideration of these technologies for the top 5 or 10 most costly or critical constraints on a quarterly basis.[2527] WATT Coalition states that market participants should be able to request the use of grid enhancing technologies, and receive an answer from the transmission provider within a defined period of time, to be evaluated against alternatives used by the transmission provider.[2528] WATT Coalition also asserts that grid enhancing technologies should be required in appropriate instances and encouraged through incentives because utilities have little incentive to deploy them under standard cost-of-service regulation,[2529] and after implementing this rule, the Commission should develop transmission incentives to complement a congestion threshold requirement, driving other creative applications of grid enhancing technologies where they would create the most value to consumers.[2530]

1189. Some commenters request more requirements regarding evaluation and/or deployment of alternative transmission technologies to meet transmission needs. WATT Coalition states that there are certain transmission technologies that are faster to deploy than traditional lines and urges the Commission to require an annual review of the Long-Term Regional Transmission Planning process and establish a fast track process for

[2527] WATT Coalition Initial Comments at 5.

[2528] *Id.* at 5-6.

[2529] WATT Coalition Reply Comments at 3.

[2530] WATT Coalition Supplemental Comments at 3.

solutions with a lead time of less than 12 months and a capital cost of less than $50 million.[2531] WATT Coalition further states that the requirement to consider dynamic line ratings and advanced power flow control devices should also apply in any case where transmission capacity is valuable but the costs of a new line are not justified.[2532]

1190. Smart Wires and WATT Coalition argue that the Commission should direct transmission providers to: (1) designate advanced power flow control devices as the default solution for projects requiring a series capacitor; (2) "require evaluation of advanced power flow control devices for thermal overloads that fall within 50% of the line rating," which they argue is when such devices are often most economically advantageous; (3) require evaluation of advanced power flow control devices for interconnection-related network upgrades associated with new load connections, given that these technologies can be used to rebalance flows quickly and adjusted to mirror actual growth; and (4) mandate deployment of advanced power flow control devices as the default solution for voltage stability management on 100-plus mile AC transmission lines.[2533]

1191. Some commenters suggest that the Commission should collect additional data and require reporting on the deployment of alternative transmission technologies. PIOs and

[2531] WATT Coalition Initial Comments at 8.

[2532] *Id.* at 4.

[2533] Smart Wires Initial Comments at 1, 3-5; WATT Coalition Initial Comments at 3-4.

DC and MD Offices of People's Counsel ask the Commission to require that transmission providers explain how they considered alternative transmission technologies in the transmission planning process and if they were not used, why.[2534] DC and MD Offices of People's Counsel assert that data collected from dynamic line ratings should be shared with stakeholders to provide transparency as to the necessity or economic efficiency of certain transmission upgrades, and a mechanism should be implemented to independently review the projected costs and benefits of advanced transmission technologies from an efficiency and cost-allocation perspective.[2535] NASEO states that the Commission should include a requirement for those seeking to make changes to RTOs/ISOs' facilities to provide an analysis of the new technologies and how they meet present and expected future challenges, suggesting that RTOs/ISOs be required to consult with US DOE, the DOE national laboratories, and state energy offices to ensure new technologies are incorporated into Long-Term Regional Transmission Planning.[2536] Certain TDUs argue that the Commission should require transmission planners to document their evaluation of alternative transmission solutions in the transmission planning process, which should include the methods used to integrate grid enhancing technologies alone or in combination with transmission upgrades.[2537]

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[2534] DC and MD Offices of People's Counsel Initial Comments at 36; PIOs Initial Comments at 22.

[2535] DC and MD Offices of People's Counsel Initial Comments at 36.

[2536] NASEO Initial Comments at 6-7.

[2537] Certain TDUs Reply Comments at 8-9 (citing OMS Initial Comments at 9;

1192. ENGIE recommends that the Commission require transmission providers to provide a report to the Commission every five years on the deployment and operational analysis of grid enhancing technologies to ensure these technologies are being properly evaluated in Long-Term Regional Transmission Planning.[2538] R Street suggests that the Commission require the incorporation, not just consideration, of advanced transmission technologies, and should require the inclusion of commercially viable technologies on a rolling basis as informed by a regularly updated list of qualifying technologies through, for example, a periodic forum with technology experts from US DOE.[2539] SEIA states that the Commission should host regular technical conferences to discuss improvements and innovations in grid enhancing technologies as experience with these technologies grows.[2540] SEIA states that to determine whether such technologies are feasible, transmission providers should provide the following information to market participants: modeling assumptions, contingency analysis results, asset age, and environmental and footprint constraints.[2541]

1193. Pattern Energy states that the Commission should be mindful that limited supplies of dynamic line ratings, advanced power flow control devices, and SCADA-based

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Certain TDUs Initial Comments at 24).

[2538] ENGIE Initial Comments at 6.

[2539] R Street Initial Comments at 4.

[2540] SEIA Initial Comments at 21.

[2541] *Id.* at 22.

implementation equipment (and service providers thereto) may cause shortages that will constrain transmission facility developers and owners.[2542] Pattern Energy adds that, when evaluating the costs to implement such devices, transmission providers may need to assume cost parameters (e.g., cost per mile or cost per installation) for such devices in order to have an "apples-to-apples comparison."[2543]

### 3. Need for Reform

1194. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not require consideration of alternative transmission technologies in the regional transmission planning process. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the Commission's existing regional transmission planning requirements fail to ensure that transmission providers consider whether to incorporate alternative transmission technologies into regional transmission facilities as part of their regional transmission planning processes and, consequently, fail to ensure that transmission providers are identifying more efficient or cost-effective regional transmission solutions through those processes. As a result, transmission providers overlook or undervalue the benefits of certain alternative transmission technologies and, in turn, undertake relatively inefficient and less cost-effective

[2542] Pattern Energy Initial Comments at 29-30.

[2543] *Id.* at 30.

investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, we find that existing regional transmission planning requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates.

1195. In the NOPR, the Commission stated that commercially available alternative transmission technologies have the potential to improve the operation of new and existing transmission facilities and defer or mitigate the need for new transmission investments.[2544] However, existing regional transmission planning processes are not necessarily designed to consider the benefits that alternative transmission technologies can provide.[2545] Commenters state that some transmission providers are reluctant to implement alternative transmission technologies or that alternative transmission technologies are not consistently evaluated in regional transmission planning in a manner commensurate with the benefits that they can provide.[2546] The failure to consistently consider these technologies in regional transmission planning prevents them from being identified, evaluated, and selected as a more efficient or cost-effective solution to transmission needs, to the detriment of customers that can benefit from their deployment.

[2544] NOPR, 179 FERC ¶ 61,028 at P 267.

[2545] *See, e.g.*, AEE Initial Comments at 29.

[2546] Certain TDUs Initial Comments at 22-23; Invenergy Initial Comments at 15-16; NASUCA Initial Comments at 7; WATT Coalition Initial Comments at 4.

1196. The record demonstrates that alternative transmission technologies can provide significant capacity increases when incorporated into transmission facilities, and that such incorporation may provide benefits that outweigh its costs.[2547] For example, a white paper prepared by the Brattle Group highlights several recent examples in which dynamic line ratings, transmission switching, and advanced power flow control devices were deployed to cost-effectively meet transmission needs in SPP, MISO, and other utility service territories.[2548] Additionally, a recent US DOE case study on dynamic line ratings and advanced power flow control devices estimates that these alternative transmission technologies can provide significant production cost savings, net import savings, and avoided curtailment savings.[2549]

1197. We find that the failure to require transmission providers to consider alternative transmission technologies renders the Commission's existing regional transmission planning requirements insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206,

[2547] *See, e.g.*, WATT Coalition Supplemental Comments at 2-3.

[2548] The Brattle Group, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts* 12-15 (Apr. 20, 2023), https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf.

[2549] US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact* v-x (Feb. 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

that transmission providers consider in Long-Term Regional Transmission Planning and their existing Order No. 1000 regional transmission planning process the alternative transmission technologies discussed below. While the record indicates that some of the alternative transmission technologies enumerated in this final rule are sometimes considered in certain transmission planning regions as solutions to specific transmission needs,[2550] we find that inconsistent consideration of alternative transmission technologies in regional transmission planning results in transmission providers overlooking or undervaluing the benefits that these technologies can provide. We find that the reforms concerning the consideration of alternative transmission technologies that we adopt in this final rule will render the Commission's existing regional transmission planning requirements just and reasonable, because they will result in transmission providers identifying, evaluating, and selecting regional transmission facilities that are more efficient or cost-effective, which will ensure that Commission-jurisdictional rates are just and reasonable.

#### 4. Commission Determination

1198. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, dynamic line ratings and advanced power flow control devices for each identified transmission need. We modify the NOPR proposal to require that, in addition

[2550] *See* Exelon Initial Comments at 21-23.

to dynamic line ratings and advanced power flow control devices, transmission providers must consider in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes advanced conductors and transmission switching. Thus, under this modification, transmission providers must consider: (1) dynamic line ratings;[2551] (2) advanced power flow control devices;[2552] (3) advanced conductors;[2553] and (4) transmission switching.[2554] We clarify that transmission providers must consider each of these enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities.[2555] Thus,

[2551] A dynamic line rating is "a transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating, transmission line tension, or transmission line sag." NOPR, 179 FERC ¶ 61,028 at P 259 n.408 (citations omitted); *see also* Order No. 881, 177 FERC ¶ 61,179 at P 7; *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 at P 1.

[2552] Advanced power flow control devices serve a transmission function. These devices can help the system operator control power flows over a given path and can include phase shifting transformers (also known as phase angle regulators) and devices or systems necessary for implementing optimal transmission switching. Advanced power flow control devices allow power to be pushed and pulled to alternate lines with spare capacity leading to maximum utilization of existing transmission capacity. NOPR, 179 FERC ¶ 61,028 at P 270 n.437.

[2553] Advanced conductors include present and future transmission line technologies whose power flow capacities exceed the power flow capacities of conventional aluminum conductor steel reinforced conductors. *See* Order No. 2023-A, 186 FERC ¶ 61,199 at 631.

[2554] Transmission switching is the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis.

[2555] We note that upgrades to existing transmission facilities include both: (1) the incorporation of an alternative transmission technology into an existing transmission

for each identified transmission need, when evaluating regional transmission facilities for potential selection, transmission providers must consider whether regional transmission facilities that incorporate, or solely consist of, any of the enumerated list of alternative transmission technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies.

1199. However, transmission providers' evaluation of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions. This means that, for the purposes of Long Term Regional Transmission Planning, transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in the same manner that they evaluate any Long-Term Regional Transmission Facility, and in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of this final rule. Accordingly, we require transmission providers to measure the required benefits and any additional benefits the transmission providers elect to measure, as discussed in detail in the

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facility with no additional changes to the underlying transmission facility (e.g., adding dynamic line ratings to an existing transmission facility); and (2) the incorporation of an alternative transmission technology into an existing transmission facility as part of a larger set of upgrades (e.g., adding dynamic line ratings to a transmission facility that is also being reconductored with a conventional aluminum conductor steel reinforced conductor).

Required Benefits section,[2556] and use those measured benefits in their evaluation processes to determine if a regional transmission facility that incorporates, or solely consists of, any of the enumerated list of alternative transmission technologies would more efficiently or cost-effectively address Long-Term Transmission Needs. As discussed in detail in the Evaluation and Selection of Long-Term Regional Transmission Facilities section,[2557] that determination would involve applying the transmission providers' selection criteria, which must, among other things, seek to maximize benefits accounting for costs over time without over-building transmission facilities. Similarly, for the purposes of existing Order No. 1000 regional transmission planning processes, transmission providers must consider the benefits of incorporating the enumerated alternative transmission technologies into transmission facilities in the same way that they currently evaluate regional transmission facilities in those existing processes to determine if a regional transmission facility incorporating any of the enumerated transmission technologies would be a more efficient or cost-effective regional transmission solution.

1200. In response to concerns regarding the mandatory consideration of the enumerated alternative transmission technologies for new regional transmission facilities,[2558] and the

[2556] *Supra* Required Benefits section.

[2557] *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[2558] CAISO Initial Comments at 6; Exelon Initial Comments at 21-22.

incremental increase in costs associated with incorporating an alternative transmission technology into new regional transmission facilities or upgrades to existing transmission facilities,[2559] we reiterate that transmission providers must follow the evaluation process and selection criteria in their tariffs. As explained in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final rule, this does not require transmission providers to select any particular Long-Term Regional Transmission Facility to address Long-Term Transmission Needs (i.e., in this case it does not require the selection and deployment of any particular alternative transmission technology with regard to any particular Long-Term Transmission Need).[2560] We recognize that, in addition to considering the costs and benefits associated with incorporating alternative transmission technologies into transmission facilities, transmission providers must continue to follow Good Utility Practice with regard to planning, evaluating, selecting, constructing, operating, and maintaining all transmission facilities, whether such transmission facilities are considered and implemented through existing regional transmission planning processes or as part of Long-Term Regional Transmission Planning as set forth in this final rule.[2561]

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[2559] Exelon Initial Comments at 19-20.

[2560] *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[2561] *See pro forma* OATT § 28.2 (Transmission Provider Responsibilities) ("The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service

1201. We find that it is appropriate to require transmission providers to consider whether it may be more efficient or cost-effective to incorporate the enumerated alternative transmission technologies into both new regional transmission facilities and upgrades to existing transmission facilities because the record indicates that such technologies can provide benefits by improving the efficiency of transmission facilities, regardless of whether the facilities are already in-service or yet to be deployed.[2562] We find that incorporating the enumerated alternative transmission technologies as upgrades to existing transmission facilities has the potential to make the use of existing transmission infrastructure more efficient and optimize the performance of such infrastructure, mitigating or deferring the need for development of new regional transmission facilities.[2563] Adding alternative transmission technologies to new regional transmission facilities may provide cost savings by improving operational efficiency of transmission facilities. Further, incorporating alternative transmission technologies into new transmission facilities may present more benefits and cost less than incorporating such technologies as retrofits after the regional transmission facility is deployed. We further find that requiring transmission providers to consider the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes will ensure that transmission providers more

over the Transmission Provider's Transmission System.").

[2562] *See* WATT Coalition Supplemental Comments at 2-3.

[2563] Pattern Energy Initial Comments at 29.

fully consider a broader set of technologies that can address transmission needs more efficiently or cost-effectively.

1202. We clarify that the selection and use any of the enumerated alternative transmission technologies that are incorporated into an existing transmission facility should be treated as an upgrade to an existing transmission facility. Order No. 1000's elimination of any federal right of right of first refusal for selected transmission facilities does not apply to upgrades to an existing transmission facility.[2564] Therefore, an incumbent transmission provider would be designated to develop any alternative transmission technology that is selected for incorporation into that incumbent transmission provider's existing transmission facilities as the more efficient or cost-effective solution.

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[2564] The Commission stated in Order No. 1000 that the non-incumbent transmission developer reforms:

> do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. In other words, an incumbent transmission provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities.

Order No. 1000, 136 FERC ¶ 61,051 at P 319 (footnote omitted). The Commission clarified that "the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility." Order No. 1000-A, 139 FERC ¶ 61,132 at P 426. The Commission further clarified that the requirement to eliminate a federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way. *Id.* P 427.

1203. With respect to alternative transmission technologies added or deployed on a *new* selected regional transmission facility, we clarify that the transmission developer that is designated to develop the underlying selected regional transmission facility, whether that developer is an incumbent transmission provider or a nonincumbent transmission developer, must also be designated to develop any alternative transmission technologies selected to be incorporated into the regional transmission facility, and thus, would be eligible to use the applicable regional cost allocation method.[2565] For example, in a competitive bidding model, the transmission developer that submits the winning bid for a selected new regional transmission facility that includes an alternative transmission technology would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies. Similarly, in a sponsorship model, the transmission developer that sponsors a new regional transmission facility that includes any alternative transmission technologies would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies, consistent with the selection.

1204. We further clarify that, under a sponsorship model, transmission providers' addition of an alternative transmission technology to a sponsored regional transmission facility proposal that is ultimately selected must not lead to the original sponsored

[2565] *See* FERC, Staff Report, *2017 Transmission Metrics* 8 (Oct. 6, 2017), https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf (describing the two general types of competitive transmission development processes, the "competitive bidding model" and the "sponsorship model").

regional transmission facility being labeled as an unsponsored regional transmission facility. Therefore, the sponsoring developer would be eligible to use the regional cost allocation method for the selected new regional transmission facility, as modified with the alternative transmission technology.

1205. We also clarify that, for every competitive transmission development process in a given transmission planning region, transmission providers must identify with sufficient detail in their OATTs the point or points in a given process at which the transmission providers in the transmission planning region will consider the potential use of alternative transmission technologies, including the point at which qualified transmission developers must submit any proposal to incorporate alternative transmission technologies. This clarification is meant to ensure transparency for competing transmission developers and other stakeholders.[2566]

1206. In response to comments that transmission providers should not be required to consider the enumerated alternative transmission technologies in regional transmission planning processes due to the costs and challenges associated with implementation,[2567] we find that the examples in the record of implementation of dynamic line ratings,

[2566] For example, in a competitive bidding model, transmission providers must make clear whether, and if so when, a qualified transmission developer can propose to incorporate alternative transmission technologies into a bid for a selected Long-Term Regional Transmission Facility. This transparency requirement ensures that competing transmission developers will be treated comparably because they will know whether and when they can propose to incorporate any additional alternative transmission technologies into a bid for a regional transmission facility that has been selected.

[2567] *See, e.g.*, ATC Reply Comments at 3.

including ERCOT's experience with dynamic line ratings since 2005 and data from Oncor from 2011 to 2013,[2568] and overall support for the consideration of advanced power flow control devices in transmission planning,[2569] sufficiently demonstrate that transmission providers are capable of considering the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes. Kansas Commission's position that consideration of alternative transmission technologies in regional transmission planning processes should be data-driven and supported by robust analysis demonstrating benefits is consistent with our determinations here.[2570] Therefore, transmission providers must consider the incorporation of these enumerated alternative transmission technologies consistent with the specific requirements for analysis and evaluation of benefits in their OATTs, including those applicable to existing regional transmission planning processes and those required in this final rule for Long-Term Regional Transmission Planning.[2571] We acknowledge Mississippi Commission's concerns about deploying alternative transmission technologies without consideration of their costs and note that, to the extent

[2568] Hannon Armstrong Reply Comments at 2-3; WATT Coalition Reply Comments at app. B.

[2569] Ameren Initial Comments at 24-25; EEI Initial Comments at 20-21; Entergy Initial Comments at 29; Exelon Initial Comments at 23.

[2570] Kansas Commission Initial Comments at 19-20.

[2571] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

that a transmission provider selects a regional transmission facility that incorporates an enumerated alternative transmission technology, the transmission provider would only do so after evaluating the costs and benefits of that transmission facility, including the incorporation of the alternative transmission technology.[2572]

1207. We disagree with commenter assertions that alternative transmission technologies are only operational tools and that transmission providers cannot rely on any additional capacity created by these technologies for the purpose of meeting transmission needs.[2573] We note that Long-Term Regional Transmission Planning and existing regional transmission planning processes are designed to address a variety of needs, including not only reliability needs but also Long-Term Transmission Needs and economic needs. These processes are well-suited to evaluate the economic benefits of the enumerated alternative transmission technologies, which are relevant to assessing whether a regional transmission facility that incorporates such technologies is more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies. We believe that the particular benefit measurement methods that transmission providers must develop, pursuant to requirements discussed below, to evaluate proposed Long-Term Regional Transmission Facilities can be used to measure

[2572] Mississippi Commission Reply Comments at 8.

[2573] AEP Initial Comments at 6, 33; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26-28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36-37.

the economic benefits of incorporating the enumerated alternative transmission technologies into transmission facilities.[2574] As more fully described above in the Required Benefits section, these benefits include, but are not limited to, methods to measure production cost savings, reduced congestion due to fewer transmission outages, and capacity cost benefits from reduced peak energy losses. Similarly, we find that the enumerated alternative transmission technologies can provide those economic benefits that are already evaluated in existing regional transmission planning processes. Finally, contrary to commenters' concerns, the record here demonstrates that certain alternative transmission technologies are in some cases capable of enhancing reliability and providing additional capacity.[2575]

1208. In response to concerns about administrative burden and assertions that predictions about benefits are speculative,[2576] we find that the potential advantages associated with adopting this reform (i.e., identifying more efficient or cost-effective regional

[2574] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

[2575] *See infra* P 1241 for a more detailed discussion of the reliability benefits of dynamic line ratings and advanced power flow control devices; *see also* Ameren Initial Comments at 24; Bekaert Supplemental Comments at 1-2; CTC Global Initial Comments at 15.

[2576] ATC Initial Comments at 10; Duke Initial Comments at 30-31 (citing attach. A, Robert Pierce Aff. ¶¶ 8-9); ISO-NE Initial Comments at 40-41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19-20; Large Public Power Initial Comments at 32-33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 22; Pacific Northwest Utilities Initial Comments at 15-16; SERTP Sponsors Initial Comments at 36-37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶ 16; US Chamber of Commerce Initial Comments at 9.

transmission solutions) outweigh the potential administrative and analytical burden. As it pertains to dynamic line ratings, the information needed to inform the calculation of dynamic line ratings should be widely available. For example, NREL has published data on annual averages of windspeeds at 10 meters above the ground that could inform predictions for future wind conditions to facilitate calculations of economic benefits.[2577] For the calculation of the economic benefits associated with dynamic lines ratings, it is appropriate for such calculations to use historical average wind speed and direction data to calculate average increases to transmission line transfer limits for use in benefit calculations. Average predicted wind speeds and direction should be sufficient to inform the transmission provider as to whether the implementation of dynamic line ratings on a specific transmission line may render that line a more efficient or cost-effective regional transmission solution, and such data are widely available.[2578] We acknowledge that there is uncertainty with projections of any kind; however, it is not necessary to understand the

[2577] Data on annual averages of windspeeds at 10 meters above the ground is published by NREL in the form of both maps and tabular data. *See* NREL, *Wind Resource Maps and Data*, https://www.nrel.gov/gis/wind-resource-maps.html. As another example, data on monthly prevailing wind direction is published by the U.S. Department of Agriculture for various cities in all U.S. states in the form of graphical "wind roses." *See* U.S. Dep't. of Agric., National. Weather and Climate Center, https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/.

[2578] *See, e.g.*, NREL, *Wind Resource Maps and Data*, https://www.nrel.gov/gis/wind-resource-maps.html; U.S. Dep't of Agric., National Weather and Climate Center, https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/.

precise future wind conditions at a specific future period to assess the expected economic benefits associated with the implementation of dynamic line ratings.

1209. In response to arguments that the Commission should favor transmission provider flexibility with respect to consideration of alternative transmission technologies,[2579] we note that the reforms adopted in this final rule provide transmission providers with an appropriate amount of flexibility and do not require the selection of any particular enumerated alternative transmission technology to address any particular transmission need. As previously discussed, this requirement will ensure that transmission providers more consistently consider the costs and benefits associated with incorporating the enumerated alternative transmission technologies into regional transmission facilities. However, we recognize that transmission providers must also continue to follow Good Utility Practice when planning, evaluating, selecting, constructing, operating, and maintaining transmission facilities.

1210. Moreover, we decline to mandate further details on how transmission providers should evaluate the enumerated list of alternative transmission technologies as more efficient or cost-effective solutions to transmission needs, beyond the requirements adopted in this final rule. Thus, in response to comments from Smart Wires and WATT Coalition proposing that the Commission mandate either consideration or deployment of

[2579] Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7-8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

advanced power flow control devices in specific situations,[2580] we find that transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to specific transmission needs.[2581]

1211. In response to commenters urging the Commission to wait for transmission providers to comply with Order No. 881 before implementing the NOPR proposal,[2582] such concerns are unpersuasive. Public utility transmission providers subject to Order No. 881 are required to implement these requirements by July 12, 2025.[2583] As the Compliance Procedures section of the final rule states, the date that transmission providers are required to begin considering the enumerated alternative transmission technologies will be the effective date of the applicable tariff provisions submitted to comply with this final rule requirement. The final rule also states that transmission providers must submit their compliance filings within ten months of the effective date of this final rule, which is 60 days from the date of publication in the Federal Register.

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[2580] Smart Wires Initial Comments at 1, 3-5; WATT Coalition Initial Comments at 3-4.

[2581] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 153 (noting that transmission providers retain the ultimate responsibility for transmission planning). As Entergy and Exelon attest, advanced power flow control devices are already considered in some transmission planning processes. *See* Entergy Initial Comments at 29; Exelon Initial Comments at 23.

[2582] ATC Reply Comments at 4-5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32-33; MISO TOs Initial Comments at 23-24.

[2583] *See MATL LLP*, 185 FERC ¶ 61,028, at P 10 (2023) (stating that July 12, 2025 is the implementation date of Order No. 881(citing Order No. 881, 177 FERC ¶ 61,179 at P 361)).

Moreover, even if the compliance submission deadline falls shortly before Order No. 881's implementation deadline, the operative date here is the date that the tariff revisions proposed in a transmission provider's compliance filing to this final rule become effective, which is the effective date requested by the submitting transmission provider and accepted by the Commission.[2584] Consequently, the transmission provider would not need to implement this final rule requirement prior to the implementation of Order No. 881 on July 12, 2025 unless it requests, and the Commission accepts, an earlier effective date for its tariff revisions.

1212. Moreover, we find that concerns raised by commenters with respect to the interactions between the requirements that we establish in this final rule and Order No. 881 to be speculative. We believe that the requirements to consider the enumerated alternative transmission technologies are separate from (but complementary to) the Commission's requirements in Order No. 881. In Order No. 881, as most relevant here, the Commission required the use of more accurate transmission line ratings using up-to-date forecasts of ambient air temperatures in transmission line ratings. By contrast, regarding the requirement to consider dynamic line ratings in this final rule, transmission providers must consider the benefits associated with additional up-to-date transmission line rating input assumptions, specifically wind speed and direction and solar heating intensity.

[2584] *See infra* Compliance Procedures section.

1213. We disagree with concerns that any mandate to consider dynamic line ratings in this proceeding might complicate the dynamic line ratings notice of inquiry (NOI) proceeding,[2585] or that a mandate to consider dynamic line ratings in this proceeding ignores the record, and the technical challenges identified in, the dynamic line ratings NOI proceeding.[2586] We find such concerns unpersuasive. Any potential future Commission action in the dynamic line ratings NOI proceeding remains hypothetical. Moreover, we expect transmission providers to consider both the benefits of dynamic line rating implementation and the challenges and costs associated with dynamic line rating implementation as part of their consideration of the technology in Long-Term Regional Transmission Planning and their existing regional transmission planning processes.

1214. In response to requests for additional transparency,[2587] we also adopt the NOPR proposal to expand the existing requirement established in Order No. 1000 for transmission providers' evaluation processes to culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected. Specifically, we adopt the NOPR proposal to require that the determination include an explanation that is sufficiently detailed for stakeholders to understand why dynamic line ratings, advanced power flow control devices, advanced

[2585] MISO TOs Initial Comments at 23-24.

[2586] Large Public Power Initial Comments at 32.

[2587] Certain TDUs Reply Comments at 8-9; DC and MD Offices of People's Counsel Initial Comments at 36; ENGIE Initial Comments at 6; PIOs Initial Comments at 22.

conductors, and/or transmission switching were or were not incorporated into selected regional transmission facilities.

1215. With regard to the Commission's request for comment on whether to require non-RTO/ISO transmission planning regions to update their energy management systems or make other similar changes if dynamic line ratings are selected as a more efficient or cost-effective regional transmission facility, we require transmission providers to update their energy management systems, if needed to implement dynamic line ratings or any of the alternative transmission technologies. We note that some transmission providers in non-RTO/ISO transmission planning regions may already be able to implement the alternative transmission technologies, and, as a result of the Commission's Ambient-Adjusted Rating requirements in Order No. 881,[2588] may have already updated their energy management systems, and therefore may not need further updates to their energy management systems. However, if a transmission provider must upgrade its energy management systems to implement any of the alternative transmission technologies, then consistent with other requirements in this final rule, we require transmission providers to consider any possible energy management system upgrade costs needed to implement the selected alternative transmission technologies as part of their broader consideration of whether transmission facilities that incorporate alternative transmission technologies are more efficient or cost-effective regional transmission solutions. We further reiterate that transmission providers must provide an explanation that is sufficiently detailed for

[2588] Order No. 881, 177 FERC ¶ 61,179 at P 84.

stakeholders to understand why any of the enumerated alternative transmission technologies were, or were not, incorporated into transmission facilities selected in the regional transmission plan for purposes of cost allocation. Moreover, we clarify that this explanation must be sufficiently clear to demonstrate whether the transmission provider did not select transmission facilities that incorporate any of the enumerated alternative transmission technologies, in part or primarily, due to concerns over the costs of upgrading energy management systems.

1216. Finally, we find that WATT Coalition's request to consider incentives for deploying alternative transmission technologies is outside the scope of this proceeding.

### B. Specific Alternative Transmission Technologies

#### 1. NOPR Proposal

1217. The Commission sought comment on whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes. The following section discusses comments on specific alternative transmission technologies that transmission providers are required to consider pursuant to the requirements of this final rule.

#### 2. Comments on Specific Technologies

1218. AEE notes that dynamic line ratings implementation will increase capacity and provide significant benefits to customers.[2589] Michigan State Entities state that dynamic

[2589] AEE Reply Comments at 29 (citing US DOE, *Dynamic Line Ratings Report to Congress 2019* 26 (June 2022), https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2

line ratings hold tremendous value for states like Michigan with cold, cloudy winters, during which there is a greater reliance on transmission to move distant wind generation.[2590]

1219. AEE states that dynamic line ratings and similar technologies are so useful because they improve predictability.[2591] AEE further contends that, in the longer-term, changing conditions will necessitate greater transmission deployment and the need for more transmission capacity, but without considering complementary technologies, the transmission buildout may be less efficient.[2592]

1220. Hannon Armstrong contends that ERCOT's experience with dynamic line ratings since 2005, as well as data from Oncor from 2011 to 2013, demonstrates that this technology can provide significant savings through reduced congestion costs, allow for granular congestion management, and furnish congestion data. According to Hannon Armstrong, real-time dynamic ratings and reliability analysis improve transmission system operation and planning, provide opportunities for congestion mitigation, and could justify the cancellation of planned transmission upgrades. Hannon Armstrong

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019_final_508_0.pdf).

[2590] Michigan State Entities Initial Comments at 10.

[2591] AEE Reply Comments at 30 (citing MISO Initial Comments at 57-58).

[2592] *Id.*

concludes that dynamic line ratings can promote just and reasonable rates without compromising reliability.[2593]

1221. As mentioned above, some commenters warn the Commission of potential reliability and operational impacts of the widespread use of dynamic line ratings.[2594] Entergy explains that it has experienced significantly different weather readings at nearby weather sensors and cautions that the 2003 blackout was partially caused by overestimating the wind in transmission line ratings.[2595]

1222. Some commenters that oppose the use of dynamic line ratings in transmission planning raise concerns about the reliability risks presented by dynamic line ratings.[2596] PJM argues that dynamic line ratings are inappropriate for addressing reliability needs and may introduce operational risk because, for example, forecasted wind might not materialize and the actual real-time ratings would be lower than forecasted.[2597] Southern

[2593] Hannon Armstrong Reply Comments at 2.

[2594] Duke Initial Comments at 31-32 (citing attach. A, Robert Pierce Aff. ¶ 11); Entergy Initial Comments at 27-28; MISO Initial Comments at 59-60.

[2595] Entergy Initial Comments at 27-28 (citing U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* 58 (Apr. 2004)).

[2596] ATC Initial Comments at 7, 10; Duke Initial Comments at 31; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; LADWP Initial Comments at 5; NRECA Initial Comments at 53; PJM Initial Comments at 108-109; Southern Initial Comments at 35 (citing Ex. 2, Daryl C. McGee at ¶ 17); SERTP Sponsors Initial Comments at 36-37.

[2597] PJM Initial Comments at 108-109.

argues that the assumption of dynamic line ratings leading to additional capacity will likely result in reduced system expansion, which could cause reliability problems in the long run.[2598] Large Public Power and LADWP maintain that there is meaningful cybersecurity risk associated with the communications equipment needed to support dynamic line ratings.[2599] However, WATT Coalition states that both traditional transmission solutions and grid enhancing technologies can result in problems, so the impact of solutions should be evaluated carefully to ensure that a solution to one problem does not create another.[2600]

1223. Some commenters argue that dynamic line ratings are operational in nature and do not belong in the transmission planning process.[2601] Dominion and Exelon state that a transmission provider must plan and build its system for worst case scenarios, which limits the usefulness of dynamic line ratings in transmission planning.[2602] ITC asserts

[2598] Southern Initial Comments at 35, Ex. 2, Daryl McGee at ¶ 17.

[2599] LADWP Initial Comments at 5; Large Public Power Initial Comments at 35.

[2600] WATT Coalition Reply Comments at 4-5.

[2601] AEP Initial Comments at 33; Dominion Initial Comments at 40; Duke Initial Comments at 5; EEI Initial Comments at 21-22; Entergy Initial Comments at 5-6; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; ISO-NE Initial Comments at 40-41; ITC Initial Comments at 6, 26-28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); MISO Initial Comments at 57; MISO TOs Initial Comments at 23; NRECA Initial Comments at 52; Pacific Northwest Utilities Initial Comments at 15-16; PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36-37; US Chamber of Commerce Initial Comments at 9.

[2602] Dominion Initial Comments at 40; Exelon Initial Comments at 22.

that transmission systems must be planned based on actual transfer capacity under the worst-case scenario, and not on contingent, variable capacity of the type that dynamic line ratings provide.[2603] EEI and Entergy note that the inherent variability and unpredictability associated with wind speed, solar heating intensity, and transmission line tension make dynamic line ratings inappropriate for addressing longer-term system planning objectives.[2604] MISO adds that for transmission planning horizons of five to 20 years or more into the future, it is impossible to predict the real-time conditions on which dynamic line ratings are based.[2605] NRECA explains that dynamic line ratings are not a substitute for an upgraded or new transmission facility.[2606]

1224. Many opposing commenters argue that the benefits of dynamic line ratings are too speculative.[2607] MISO states that dynamic line ratings may not always produce the benefits anticipated, explaining that static ratings are typically based on conservative wind speeds and best-case wind direction, so the assumptions used to develop static

[2603] ITC Initial Comments at 26.

[2604] EEI Initial Comments at 21; Entergy Initial Comments at 27.

[2605] MISO Initial Comments at 57-58.

[2606] NRECA Initial Comments at 52.

[2607] ATC Initial Comments at 10; Duke Initial Comments at 30 (citing attach. A, Robert Pierce Aff. ¶ 8); ISO-NE Initial Comments at 40-41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19-20; Large Public Power Initial Comments at 32-33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 22; Pacific Northwest Utilities Initial Comments at 15-16; SERTP Sponsors Initial Comments at 36-37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16-17; US Chamber of Commerce Initial Comments at 9.

ratings are not always worst-case.[2608] ISO-NE asserts that, for example, under summer peak load conditions, the dynamic line rating would be the same as that assumed in the planning study.[2609] Southern cautions that including dynamic line ratings in transmission planning would likely assume additional capacity that may not materialize in real time, increasing congestion.[2610] Large Public Power and MISO TOs argue that dynamic line ratings do not provide sufficient incremental benefits over Ambient Adjusted Ratings to justify the additional expense.[2611]

1225. Some commenters argue that advanced power flow control devices are appropriate technologies to consider in transmission planning, contrasting them with dynamic line ratings.[2612] Southern states that it generally supports consideration of advanced power flow control devices, and Ameren argues that they may be appropriate in certain circumstances for regional transmission planning.[2613] Additionally, while WATT Coalition agrees that conductor-mounted advanced power flow control devices are

[2608] MISO Initial Comments at 58.

[2609] ISO-NE Initial Comments at 40-41.

[2610] Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16-17.

[2611] Large Public Power Initial Comments at 32-33; MISO TOs Initial Comments at 24.

[2612] EEI Initial Comments at 20-21; Entergy Initial Comments at 29; Exelon Initial Comments at 23-24.

[2613] Ameren Initial Comments at 24-25; Southern Initial Comments, Ex. 2, Daryl C. McGee at ¶ 15.

limited in impact, it contends that today's ground-mounted versions can significantly increase transfer capacity and integration of renewables.[2614]

1226. Industrial Customers assert that the Commission should compel the use of advanced power flow control devices because they are instrumental to ensuring that transmission lines are fully used to their safest and most efficient potential.[2615] Industrial Customers further argue that the use of advanced power flow control devices will allow for the optimization of transmission lines under various weather conditions.[2616] Smart Wires states that advanced power flow control devices can provide a more affordable means of servicing the type of load growth driving Long-Term Regional Transmission Facilities.[2617] In addition, Smart Wires argues that several system studies have verified that advanced power flow control devices avoid sub-synchronous resonance events on long radial transmission lines, which can result in extensive damage.[2618]

1227. In response to the administrative burden of considering advanced power flow control devices specifically, WATT Coalition states that it provides guidance and evidence of successful modeling schemes for such devices.[2619] WATT Coalition argues

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[2614] WATT Coalition Reply Comments at 4.

[2615] Industrial Customers Reply Comments at 13-14.

[2616] *Id.* at 18-19 (citing PPL, Initial Comments, Docket No. AD22-5-000, at 3 (filed Apr. 25, 2022)).

[2617] Smart Wires Initial Comments at 3-4.

[2618] *Id.* at 1, 4.

[2619] WATT Coalition Reply Comments at 3 (citing app. C).

that advanced power flow control devices are a valuable solution to limitations of power system studies because they can be adjusted by grid operators for unforeseen grid challenges.[2620] WATT Coalition adds that advanced power flow control devices have a granular dispatchability that can also support real-time operational needs, which may differ from those identified in the transmission planning timeframe.[2621]

1228. Similar to dynamic line ratings, many commenters argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes.[2622] Duke and MISO caution against widespread deployment of advanced power flow control devices.[2623] Duke argues that they should be applied judiciously, and that increased deployment creates a greater risk of wide area cascading events by increasing the probability of the system being in a previously unanalyzed state.[2624] MISO states that, while advanced power flow control devices work best to address specific isolated issues, it is not feasible to coordinate the operation and deployment of these devices en masse, either manually or automatically.

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[2620] *Id.* at 4.

[2621] *Id.*

[2622] AEP Initial Comments at 6; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26-28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36-37.

[2623] Duke Initial Comments at 31-32; MISO Initial Comments at 59-60.

[2624] Duke Initial Comments at 31-32.

According to MISO, deployment of these devices could create other issues, and thus their operation and deployment must be managed on a holistic basis.[2625] MISO further states that advanced power flow control devices could result in continued cascading issues across the system because of the potential widespread impact of adjusting line impedances that may get pushed to other facilities.[2626]

1229. A number of commenters assert that the Commission should expand the list of alternative transmission technologies that must be considered.[2627] Several commenters suggest that the Commission should require transmission providers to consider specific additional technologies in Long-Term Regional Transmission Planning, including storage that performs a transmission function, advanced conductors, transmission switching, topology optimization, and dynamic reactive power devices.[2628] Some federal legislators

[2625] MISO Initial Comments at 59.

[2626] *Id.* at 60.

[2627] ACEG Initial Comments at 31; ACORE Initial Comments at 16; ACORE Supplemental Comments at 1; AEE Reply Comments at 27-28; Bekaert Supplemental Comments at 1; Breakthrough Energy Initial Comments at 16; CARE Coalition Initial Comments at 2-3; CARE Coalition Reply Comments at 5; Certain TDUs Reply Comments at 8-9; City of New York Reply Comments at 4 (citing PIOs Initial Comments at 84); Clean Energy Associations Initial Comments at 27-28; Clean Energy Associations Reply Comments at 7; CTC Global Initial Comments at 14-15; Industrial Customers Reply Comments at 11; Invenergy Initial Comments at 16; Vermont State Entities Initial Comments at 9.

[2628] Dynamic reactive power is produced from equipment that can quickly change the Mvar level independent of the voltage level. Thus, the equipment can increase its reactive power production level when voltage drops and prevent a voltage collapse. Static VAR compensators, synchronous condensers, and generators provide dynamic reactive power. FERC, Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption* 7 (Feb. 4, 2005),

agree, offering support for a requirement to consider energy storage, reconductoring using advanced conductors,[2629] and topology optimization.[2630] AEE argues that expanding the list of technologies that must be considered in transmission planning would fulfill the Commission's obligations under the FPA to encourage the adoption of advanced transmission technologies.[2631]

1230. Several commenters urge the Commission to require that storage be considered.[2632] CARE Coalition states that utilities can use storage to defer investments

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https://www.ferc.gov/sites/default/files/2020-04/20050310144430-02-04-05-reactive-power.pdf.

[2629] Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2.

[2630] Environmental Legislators Caucus Supplemental Comments at 2.

[2631] AEE Reply Comments at 27-28, 34 (citing 42 USC 16422(b)).

[2632] Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 33-34; CAISO Initial Comments at 38; California Commission Initial Comments at 38-40 (citing Jennifer Chen & Devin Hartmann, *Transmission Reform Strategy From A Customer Perspective: Optimizing Net Benefits And Procedural Vehicles R Street Policy Study* 7 (May 2022), https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf); CARE Coalition Initial Comments at 2-3; Clean Energy Associations Initial Comments at 30-31; Conservative Energy Network Supplemental Comments at 1-2; Conservatives for Clean Energy – Florida Supplemental Comments at 1-2; Conservatives for Clean Energy – South Carolina Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36-37; Illinois Commission Initial Comments at 12; Industrial Customers Reply Comments at 11; Joint Consumer Advocates Initial Comments at 13; Michigan Conservative Energy Forum Supplemental Comments at 1; NARUC Initial Comments at 36; National Grid Initial Comments at 3-4; Ohio Conservative Energy Forum Supplemental Comments at 1; OMS Initial Comments at 9; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

as supply and demand patterns change, allowing them to avoid all-in, 50-year investments in favor of shorter-term flexibility.[2633] CARE Coalition cites a number of ways that storage can improve transmission, including providing voltage support in a transmission-constrained zone, ensuring reliability while repairs are executed, reducing peak loads, increasing capacity on congested lines, directing power flow away from lower capacity transmission lines, and controlling the timing of power flows to remain under thresholds.[2634]

1231. AEP states that the Commission should require better consideration of storage, noting that the technology has advanced significantly in the past several years, yet is still not being deployed as a transmission alternative. AEP cites two reasons for this: (1) despite the multiple uses and benefits of storage, it is currently categorized as only one of the following – transmission, generation, or distribution, and (2) there is no traditional approach that assesses the viability of storage proposals to solve reliability problems. AEP states that, to solve these problems, the Commission should provide more certainty around these questions, including how to schedule, dispatch, and charge storage, as well as guidance on how to assess the value of storage beyond reliability if, for example, the resource is only needed during certain times of year.[2635]

[2633] CARE Coalition Initial Comments at 42-43.

[2634] *Id.* at 42.

[2635] AEP Initial Comments at 33-34.

1232. Some commenters suggest that the Commission should require consideration of advanced conductors in Long-Term Regional Transmission Planning.[2636] CTC Global asserts that advanced conductors should be required to be considered because of their ease of installation onto existing structures, cost savings, lower line sag, and power flow increase.[2637] CTC Global adds that even in the case of a total rebuild, advanced conductors can generate more capacity, efficiency, resilience, and reliability than rebuilds using standard conductors.[2638] VEIR notes that if the final rule requires the consideration of advanced conductors, the Commission should define advanced conductors to include all advanced conductor technologies, including superconductors.[2639] Bekaert states that the definition of advanced conductors should extend beyond carbon fiber core technologies to also include steel core technologies, which it contends can raise ampacity, reduce line losses, and withstand extreme weather conditions, all while offering a cost-effective solution.[2640]

[2636] ACEG Initial Comments at 31; ACORE Initial Comments at 16; Breakthrough Energy Initial Comments at 15-19; CTC Global Initial Comments at 15-16; DC and MD Offices of People's Counsel Initial Comments at 36-37; Indicated US Senators and Representatives Initial Comments at 2; NASEO Initial Comments at 6; Prysmian Initial Comments at 1; VEIR Initial Comments at 5-6.

[2637] CTC Global Initial Comments at 14-15.

[2638] *Id.* at 15.

[2639] VEIR Reply Comments at 5.

[2640] Bekaert Supplemental Comments at 1-2.

1233. Some commenters suggest that the Commission should require consideration of transmission switching in Long-Term Regional Transmission Planning.[2641] For example, Illinois Commission states that line switching is a tool to make better use of the extant transmission system.[2642] NASEO states that the use of alternative transmission technologies, including transmission switching, is increasing.[2643] However, MISO argues that grid enhancing technologies that introduce automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered remedial action schemes, which MISO and its transmission owners have attempted to reduce as a matter of Good Utility Practice.[2644]

1234. A number of commenters suggest that the Commission should require consideration of topology optimization in Long-Term Regional Transmission Planning.[2645] Potomac Economics states that network optimization can allow a

[2641] Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

[2642] Illinois Commission Initial Comments at 12 (citing Pablo A. Ruiz, The Brattle Group, *Transmission Topology Optimization* (Aug. 21, 2017) https://www.brattle.com/wp-content/uploads/2017/10/7204_transmission_topology_optimization.pdf (Brattle Group Aug. 2017 Report)).

[2643] NASEO Initial Comments at 6.

[2644] MISO Initial Comments at 60.

[2645] ACORE Initial Comments at 16; CARE Coalition Initial Comments at 2-3; ENGIE Initial Comments at 5-6; Illinois Commission Initial Comments at 11-13 (citing Brattle Group Aug. 2017 Report); Indicated US Senators and Representatives Initial Comments at 2; Potomac Economics Initial Comments at 5; R Street Initial Comments at 4; Tabors Caramanis Rudkevich Initial Comments at 5; WATT Coalition Initial

transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.[2646] With respect to topology optimization, WATT Coalition recommends that the information provided in the evaluation process should include modeling assumptions, contingency analysis results, asset age and condition, environmental and footprint constraints, etc.[2647] In contrast, SPP states that technologies that optimize transmission system operation should be considered short-term solutions and not a replacement for long-term transmission capacity.[2648]

1235. ITC argues that the Commission should encourage transmission providers to modernize transmission planning criteria to better consider dynamic reactive power devices such as static VAR compensators, static synchronous compensators, and unified power flower controllers. ITC asserts that such technologies provide faster response times to changes in voltage and power factor, relative to capacitor banks and mechanically switched compensation schemes.[2649]

1236. Industrial Customers and Ohio Consumers suggest that the Commission should require the consideration of distributed energy resources in Long-Term Regional

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Comments at 6.

[2646] Potomac Economics Initial Comments at 5.

[2647] WATT Coalition Initial Comments at 6.

[2648] SPP Initial Comments at 26.

[2649] ITC Initial Comments at 28.

Transmission Planning.[2650] Industrial Customers contend that demand response and load-limiting devices should be considered as a way of optimizing the current transmission system, claiming that they are less costly than transmission expansions.[2651] QCo states that the Commission should consider the use of the thermal mass of major buildings as a low-cost method to store energy and provide flexibility to the grid.[2652]

1237. ENGIE asserts that the Commission should require consideration of dynamic transformer rating technology in Long-Term Regional Transmission Planning.[2653]

1238. Exelon is concerned that making a list of technologies to consider in transmission planning will result in a "time-consuming check-the-box exercise," increasing costs and creating litigation opportunities.[2654]

### 3. Commission Determination

1239. As stated above, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.

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[2650] Industrial Customers Initial Comments at 35; Ohio Consumers Initial Comments at 34.

[2651] Industrial Customers Reply Comments at 11.

[2652] QCo Initial Comments at 1-3.

[2653] ENGIE Initial Comments at 5-6.

[2654] Exelon Initial Comments at 23-24.

1240. In response to comments that dynamic line ratings are operational in nature and are inappropriate in transmission planning, we continue to believe that there is enough real-world operational experience with dynamic line ratings for transmission providers to be able to reasonably project their likely operations and, as such, the benefits that regional transmission facilities that incorporate dynamic line ratings can provide over the transmission planning horizon.[2655] Dynamic line ratings have the ability to increase transmission line ratings, and thus permit more economic energy transfers in most intervals,[2656] which, in turn, could result in benefits (including, but not limited to, production cost savings, reduced congestion due to fewer transmission outages resulting from improved situational awareness, and capacity cost benefits from reduced peak energy losses) that we require transmission providers to evaluate in Long-Term Regional Transmission Planning, [2657] and in their existing regional transmission planning processes.

1241. We acknowledge commenter concerns about the potential effects that the widespread use of dynamic line ratings or advanced power flow control devices could have on reliability.[2658] But while these technologies cannot solve all reliability needs, as noted above, the record here demonstrates that alternative transmission technologies are

[2655] NOPR, 179 FERC ¶ 61,028 at P 276.

[2656] Hannon Armstrong Reply Comments at 1-3.

[2657] *See supra* Required Benefits section.

[2658] *See, e.g.*, CAISO Initial Comments at 41-42.

in certain circumstances capable of enhancing reliability and providing additional capacity.[2659] We recognize that, either dynamic line ratings or advanced power flow control devices, on their own, may be unlikely to resolve certain reliability needs that are assessed based on worst case conditions.[2660] We also reiterate that nothing in this final rule changes transmission providers' obligations to conduct transmission planning in a manner that ensures the long-term reliability of the bulk electric system.[2661] However, we find that dynamic line ratings and advanced power flow control devices can also confer reliability benefits. For example, in Order No. 881, the Commission found that, by accounting for ambient air temperatures in transmission line ratings, transmission providers can reliably increase power transfer capability, which results in significant reliability benefits.[2662] Such reliability benefits also apply to dynamic line ratings. Specifically, by accounting for actual wind conditions, dynamic line ratings can also reliably increase transfer capability and thereby provide reliability benefits. Similarly, as

[2659] *See supra* P 1206 of this section.

[2660] For example, as ISO-NE explains, the dynamic line rating may be the same as the rating already assumed in the planning study as transmission providers may need to assume worst case weather inputs to transmission line ratings. ISO-NE Initial Comments at 40-41.

[2661] See, for example, TPL-001-5.1, Transmission System Planning Performance Requirements, which establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

[2662] Order No. 881, 177 FERC ¶ 61,179 at P 85.

Ameren describes, it may be more efficient to use advanced power flow control devices, which can address stability limitations by allowing for greater use of a transmission facility.[2663]

1242. Additionally, Long-Term Regional Transmission Planning evaluates Long-Term Regional Transmission Facilities based on multiple benefits, and some existing regional transmission planning processes focus on economic benefits, while others may consider multiple benefits, including economic benefits. At a minimum, regional transmission solutions incorporating dynamic line ratings are appropriately considered as part of these processes. Given the potentially substantial economic benefits of dynamic line ratings, we find that it is important for transmission providers to consider dynamic line ratings in Long-Term Regional Transmission Planning and their existing regional transmission planning processes so as to ensure that they identify more efficient or cost-effective regional transmission facilities for selection.

1243. We also disagree with commenters that argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes. We find that the potential benefits of using advanced power flow control devices are sufficient to merit their consideration in Long-Term Regional Transmission Planning and existing regional transmission planning processes. For example, as Ameren states, where a transmission line is stability-limited from carrying more power, the use of advanced power flow controls may address the limitation and

[2663] Ameren Initial Comments at 24.

allow greater use of the line. Ameren also notes that advanced power flow controls may be beneficial in a situation where a transmission line that needs to be upgraded traverses sensitive environmental areas.[2664] Moreover, as Entergy and Exelon attest, advanced power flow control devices are already considered in some transmission planning processes.[2665] As discussed above, we modify the NOPR proposal to add two additional alternative transmission technologies to the list of enumerated alternative transmission technologies required to be considered in Long-Term Regional Transmission Planning and existing regional transmission planning: advanced conductors and transmission switching. We find that advanced conductors may greatly increase the capacity of transmission facilities, and thus a new regional transmission facility or upgrade to an existing transmission facility that incorporates advanced conductors may be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not incorporate such technologies. Consistent with Order No. 2023, we note that advanced conductors can increase transmission line ratings, providing more "headroom" on the system to address normal and contingency conditions.[2666] We clarify that the definition of advanced conductors that we adopt in this final rule constitutes a range of permissible present and future technologies, and is defined relative to conventional aluminum conductor steel reinforced conductors. Therefore, advanced conductors

[2664] *Id.*

[2665] Entergy Initial Comments at 29; Exelon Initial Comments at 23.

[2666] Order No. 2023, 184 FERC ¶ 61,054 at P 1597.

include, but are not limited to, superconducting cables, advanced composite conductors, advanced steel cores, high temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors. We find that such advanced conductors can result in lower line sag and increased power flow and can be installed on existing transmission structures, thereby offering ease of installation.[2667]

1244. We agree with commenters that suggest that transmission switching should be added to the list of alternative transmission technologies that must be considered in Long-Term Regional Transmission Planning and existing regional transmission planning processes.[2668] We clarify that, in this final rule, we define transmission switching as the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis. Transmission switching can be used to route energy around areas with high congestion and improve the overall transfer capability of the system. In doing so, transmission switching may provide additional economic or reliability benefits, which could therefore render a transmission facility that uses transmission switching a more efficient or cost-effective alternative than a regional transmission facility that does not use transmission switching. In response to MISO's concern that automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered

[2667] CTC Global Initial Comments at 14-15.

[2668] Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

remedial action schemes, [2669] we note that there are appropriate applications for transmission switching that offer the potential to be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not use one of the enumerated alternative transmission technologies. For example, the record indicates that network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.[2670]

1245. We decline to add storage that performs a transmission function to the list of enumerated alternative transmission technologies. The Commission has determined that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis of either how a particular electric storage resource would be operated or the requirements set forth in an OATT governing selection of such electric storage resources.[2671] In the context of regional transmission planning, we continue to find that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis, and therefore decline to generically require the consideration of storage that performs a transmission function in regional transmission planning processes.

[2669] MISO Initial Comments at 60.

[2670] Potomac Economics Initial Comments at 5.

[2671] Order No. 2023, 184 FERC ¶ 61,054 at P 1599.

1246. For the following reasons, we also decline to add topology optimization to the list of enumerated alternative transmission technologies because it is technically much more challenging to implement. We clarify that topology optimization is not specific to individual transmission facilities but instead is the act of determining the optimal use of the transmission system, which may involve many different transmission facilities. Additionally, the optimal use of the transmission system may frequently change depending on system conditions throughout the operating day. By contrast, transmission switching focuses on opening or closing transmission elements in pre-determined circumstances based on prior analyses well in advance of the operational time horizon.[2672] We do not find that it is necessary to require the consideration of topology optimization in regional transmission planning processes currently. While topology optimization software has been used to identify potential system reconfiguration actions that could result in a reduction in real-time congestion, it has not yet been deployed due to computational complexity. Specifically, given the size and complexity of the power grid and the large number of potential optimization solutions, finding optimization solutions in the necessary real-time timelines is extremely difficult and doing so risks poor model performance and lower quality solutions, which, in turn, could adversely impact

[2672] *See supra* P 1243 of this section on transmission switching. We recognize that there may be overlap between the concepts of transmission switching and topology optimization. As noted below, nothing in this final rule precludes transmission providers from considering topology optimization solutions as an alternative transmission technology, if they so choose.

reliability. While simplifications might be possible, such simplifications risk oversimplifying, which, in turn, could also jeopardize reliability.[2673]

1247. Finally, we decline to add further additional alternative transmission technologies suggested by commenters.[2674] We note that, while commenters express support for the concept of considering additional alternative transmission technologies, in general, we do not believe that the record is sufficient to include these additional technologies on the enumerated list of alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning and existing regional transmission planning processes at this time. However, we note that nothing in this final rule precludes transmission providers from considering other alternative transmission technologies or other potential solutions in their Long-Term Regional Transmission Planning and existing regional transmission planning processes.

## VI. Regional Transmission Cost Allocation

### A. Cost Allocation for Long-Term Regional Transmission Facilities

#### 1. Cost Allocation Methods for Long-Term Regional Transmission Facilities

##### a. NOPR Proposal

1248. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise their OATTs to include: (1) a Long-Term

[2673] US DOE, *Advanced Transmission Technologies* 11-15 (Dec. 2020), https://www.energy.gov/oe/articles/advanced-transmission-technologies-report.

[2674] *See supra* PP 1235-1237.

Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities[2675] may voluntarily agree to a cost allocation method; or (3) a combination thereof.[2676]

1249. The Commission proposed to define a Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning. The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable method.[2677] The Commission proposed to define a State Agreement Process as an *ex post* cost allocation process that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning, which may apply to an individual Long-Term Regional Transmission Facility or a portfolio of such Facilities

[2675] The definition of Relevant State Entities is discussed below. *See infra* Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

[2676] NOPR, 179 FERC ¶ 61,028 at P 302. The Commission explained that, for example, a "combination" approach may entail: (1) providing a Long-Term Regional Transmission Cost Allocation Method for certain types of Long-Term Regional Transmission Facilities and providing a State Agreement Process for others; or (2) providing for cost allocation for a Long-Term Regional Transmission Facility, portfolio, or type of such facilities partially based on a Long-Term Regional Transmission Cost Allocation Method and partially based on funding contributions in accordance with a State Agreement Process. *Id.* P 302 n.510.

[2677] *Id.* P 302 n.508.

grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement can be reached). If the Commission approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method.[2678]

1250. The Commission also proposed to apply the cost allocation reforms only to new Long-Term Regional Transmission Facilities. Therefore, these proposed reforms would neither provide grounds for re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of any final rule in this proceeding, nor would they apply to the cost allocation methods associated with regional transmission facilities that address shorter-term transmission needs driven by reliability and/or economic considerations.[2679]

1251. In addition, the Commission stated that, to the extent transmission providers believe that their existing cost allocation approaches comply with the requirements adopted in any final rule in this proceeding, including those related to the agreement of Relevant State Entities, they could make such demonstration in their compliance filings in response to any final rule.[2680]

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[2678] *Id.* P 302 n.509.

[2679] *Id.* P 314.

[2680] *Id.*

**b. Comments**

**i. Interest in the Proposed Cost Allocation Reforms**

1252. Some commenters offer general support for the cost allocation reforms proposed in the NOPR.[2681]

1253. Several commenters indicate support for the proposal to require transmission providers to revise their OATTs to include: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method; or (3) a combination thereof.[2682] Clean Energy Buyers state that this proposal will provide certainty in the cost allocation process, lessening disputes that may delay transmission development.[2683] ITC suggests

[2681] *E.g.*, Breakthrough Energy Initial Comments at 6; Business Council for Sustainable Energy Initial Comments at 2; California Democratic Representatives Supplemental Comments at 2; Joint Consumer Advocates Initial Comments at 13; OMS Initial Comments at 9; Pine Gate Initial Comments at 45; WE ACT Initial Comments at 5.

[2682] Certain TDUs Initial Comments at 2, 7; City of New Orleans Council Initial Comments at 9-10; Entergy Initial Comments at 29-30; Eversource Initial Comments at 29-30; ISO-NE Initial Comments at 37; ITC Initial Comments at 28; Kentucky Commission Chair Chandler Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at PP 302-303); Michigan Commission Initial Comments at 8; NARUC Initial Comments at 51; NESCOE Initial Comments at 10; New York Commission and NYSERDA Initial Comments at 12-13; New York TOs Initial Comments at 18; North Carolina Commission and Staff Initial Comments at 15-16; NYISO Initial Comments at 48-49; OMS Initial Comments at 10; Pacific Northwest State Agencies Initial Comments at 27; Pattern Energy Initial Comments at 18; PIOs Initial Comments at 64; PJM States Initial Comments at 9-10; Resale Iowa Initial Comments at 2, 12.

[2683] Clean Energy Buyers Initial Comments at 26-27.

that the Commission look to OMS' role in State Agreement Processes as a guide for how other transmission planning regions can foster state participation in Long-Term Regional Transmission Planning.[2684] AEP asserts that clear rules set in advance provide the regulatory certainty necessary to support large, long-term transmission investments and ensure customers and developers know how the associated costs will be allocated.[2685]

1254. New Jersey Commission states that a hybrid method that allocates costs partially *ex ante*, based on reliability and economic benefits, and partially *ex post*, through a State Agreement Process/negotiated participant funding approach, could have value, arguing that negotiated cost allocations could reduce litigation and make it easier to construct beneficial transmission facilities.[2686] SEIA supports a combination of a Long-Term Regional Transmission Cost Allocation Method and a State Agreement Process, asserting that states should be allowed to assume the costs of new transmission facilities to serve their needs.[2687]

#### ii. Requested Clarifications and Concerns Related to the Proposed Cost Allocation Reforms

1255. Some commenters raise concerns and request clarifications on the proposed reforms. For example, BP contends that, in the case of a multi-value project, it is unclear

[2684] ITC Reply Comments at 28-29.

[2685] AEP Initial Comments at 35.

[2686] New Jersey Commission Initial Comments at 17, 25.

[2687] SEIA Initial Comments at 24.

whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method, as opposed to all of the costs.[2688] NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Transmission Facilities.[2689]

1256. Other commenters urge flexibility with respect to cost allocation methods and state involvement,[2690] citing regional differences,[2691] to improve the likelihood of achieving consensus between affected states.[2692] OMS stresses the need for flexibility with respect to cost allocation methods to realize the NOPR's overall objectives of cost-effective regional transmission expansion.[2693] Louisiana Commission, however, asserts that, whichever cost allocation method is adopted, it should not allow a majority to impose costs upon non-consenting states.[2694]

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[2688] BP Initial Comments at 12.

[2689] NARUC Initial Comments at 49-50.

[2690] *See, e.g.*, Entergy Initial Comments at 29-30; Eversource Initial Comments at 29-30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5-6, 11, 13.

[2691] *See, e.g.*, Dominion Initial Comments at 45; Ohio Commission Federal Advocate Initial Comments at 11.

[2692] New York TOs Initial Comments at 18; *see also* Northwest and Intermountain Initial Comments at 18.

[2693] OMS Initial Comments at 10.

[2694] Louisiana Commission Initial Comments at 33-34.

1257. Shell states that the Commission should require coastal transmission providers to explain how their Long-Term Regional Transmission Planning processes facilitate transmission planning and cost allocation for offshore wind.[2695] Shell further asserts that the Commission should require all transmission providers to account for the risk of free-ridership in their OATTs, arguing that regardless of the cost allocation method applied, the Commission should ensure that first-movers are protected from free-ridership.[2696]

1258. Some commenters express concerns about the proposed State Agreement Process.[2697] Dominion states that a practical challenge in implementing the proposed reforms will be whether having an *ex ante* cost allocation method combined with alternative proposals or some combination thereof creates an additional opportunity to debate and challenge a transmission project, resulting in delays and increased costs.[2698]

#### iii. Concerns with the Proposed Cost Allocation Reforms

1259. Some commenters generally oppose the proposed reforms. For example, Southern states that the proposal to establish a specific cost allocation process before Long-Term Regional Transmission Planning has identified actual transmission projects is too abstract

[2695] Shell Initial Comments at 17.

[2696] *Id.* at 25, 28.

[2697] We also address comments regarding the State Agreement Process in more detail below. *See infra* Proposals Relating to the Design and Operation of State Agreement Processes section.

[2698] Dominion Initial Comments at 52.

to work in practice and will most likely fail to attract requisite state support.[2699] Southern further asserts that the NOPR's proposed cost allocation processes do not satisfy the second prong of the Commission's FPA section 206 burden of proof to establish a just and reasonable replacement rate.[2700] Pacific Northwest State Agencies oppose the option in the NOPR proposal that allows transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method without involving states in its development.[2701]

#### iv. Comments on Specific Aspects of the Proposed Cost Allocation Reforms

##### (a) Use of Existing Cost Allocation Methods for Long-Term Regional Transmission Facilities

1260. Some commenters assert that they should be able to use existing cost allocation methods for Long-Term Regional Transmission Planning, with some RTOs/ISOs[2702] and RTO/ISO stakeholders[2703] supporting these arguments. Other commenters support the Commission permitting transmission providers to keep their existing processes that

[2699] Southern Initial Comments at 6-7.

[2700] *Id.* at 7 n.7.

[2701] Pacific Northwest State Agencies Initial Comments at 24-25.

[2702] *See, e.g.*, MISO Initial Comments at 61, 68; PJM Initial Comments at 116; SPP Initial Comments at 28-29.

[2703] *See, e.g.*, Ameren Initial Comments at 25-27; Avangrid Initial Comments at 28; Dominion Initial Comments at 3, 45; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13-14; PJM States Initial Comments at 11-12; Virginia Commission Staff Initial Comments at 6.

involve states in cost allocation decisions.[2704] PPL supports using the existing regional cost allocation structures as a default. PPL asserts that any change to the existing cost allocation method will require an FPA section 205 filing, and interested parties, including the states, may intervene and provide testimony and evidence regarding the appropriateness of any benefit used.[2705]

1261. APS states that it agrees with the Commission that collaboration with Relevant State Entities is a positive approach to transmission planning, but it believes that the current cost allocation process is appropriate and should not be altered. APS, noting that the Commission has determined that additional complexities and contentiousness may result from expanding the transmission planning horizon to 20 years, argues that underlying cost causation principles will apply, and, therefore, existing cost allocation processes remain appropriate.[2706]

1262. Similarly, PJM contends that the need for new or expanded transmission facilities identified through Long-Term Regional Transmission Planning would fall under the reliability or market efficiency studies that it performs today, and, therefore, the Commission should permit it to use its existing *ex ante* cost allocation methods as the default cost allocation method for transmission facilities selected through Long-Term

[2704] Avangrid Initial Comments at 28; Dominion Reply Comments at 11; Omaha Public Power Initial Comments at 4.

[2705] PPL Initial Comments at 28-29.

[2706] APS Initial Comments at 11-12.

Regional Transmission Planning (absent agreement by all affected states on an alternate method). PJM states that using its existing *ex ante* approaches will provide consistency and certainty in assigning cost responsibility.[2707] PJM States disagree, arguing that the Commission should not presume that existing cost allocation methods are just and reasonable without a full examination and input from retail regulators. According to PJM States, the factors that make PJM's existing cost allocation methods just and reasonable in the short term may not exist in the long term.[2708]

1263. PJM further requests that the Commission clarify that if a transmission provider proposes to use an existing cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning, such a proposal may not be a cause for relitigating the use of that method for transmission projects selected prior to the issuance of the final rule.[2709] MISO states that if existing cost allocation methods previously were determined to comply with the Order No. 1000 regional cost allocation principles, the Commission should not require another demonstration and should clarify that its proposals do not require transmission providers to modify or set aside any existing regional cost allocation method.[2710] Relatedly, ITC argues that the Commission should

[2707] PJM Initial Comments at 115.

[2708] PJM States Reply Comments at 5.

[2709] PJM Initial Comments at 115 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

[2710] MISO Initial Comments at 61.

allow for streamlined compliance plans from transmission providers that already have substantial long-range planning processes in place.[2711]

1264. PIOs proffer that having two distinct cost allocation methods can be unjust, unreasonable, and unduly discriminatory even if those methods are reasonable on their own, and that multiple cost allocation methods may create uncertainty, which the Commission has recognized can be a barrier to transmission development.[2712] PIOs therefore request that the Commission: (1) require transmission providers to identify and justify differences between Long-Term Regional Transmission Planning and near-term cost allocation; (2) find that compliance filings that create opportunities for "cost allocation arbitrage" may not be approved; and (3) require transmission providers to demonstrate that their current Order No. 1000 cost allocation methods are just, reasonable, and not unduly discriminatory or preferential.[2713]

1265. Dominion requests that the Commission clarify that any cost allocation method directed through this rulemaking proceeding is: (1) limited to Long-Term Regional Transmission Facilities; and (2) limited to Order No. 1000 transmission planning regions.[2714]

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[2711] ITC Initial Comments at 29-30.

[2712] PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 297).

[2713] *Id.* at 72.

[2714] Dominion Initial Comments at 49-50.

1266. Clean Energy Associations request that the Commission adopt *pro forma* cost allocation provisions that would allow for regional variation where cost allocation practices are consistent with or superior to the requirements adopted in any final rule. For example, Clean Energy Associations state, if vertically integrated public utilities subject to state-jurisdictional integrated resource planning can demonstrate that the state planning process appropriately identifies needs and assigns costs based on future planned generation consistent with state policies, certain requirements may not be applicable.[2715]

**(b) Comments on Whether Filing an *Ex Ante* Cost Allocation Method Should be Required**

1267. Some commenters support a requirement that transmission providers submit an *ex ante* cost allocation method or methods that would apply to all Long-Term Regional Transmission Facilities either in place of, or as a backstop for, a State Agreement Process.[2716] For example, Grid United suggests that the Commission mandate that transmission providers develop *ex ante* cost allocation methods for selected Long-Term Regional Transmission Facilities to remove development and financial uncertainty, provide transparency in how benefits are calculated, and ensure that cost allocation is roughly commensurate with the distribution of benefits.[2717]

[2715] Clean Energy Associations Initial Comments at 36.

[2716] *See, e.g.*, Grid United Initial Comments at 6; Illinois Commission Initial Comments at 16-17; Minnesota State Entities Initial Comments at 6; MISO TOs Initial Comments at 45-48; PIOs Initial Comments at 70; RMI Supplemental Comments at 2-3.

[2717] Grid United Initial Comments at 6.

1268. MISO TOs state that *ex ante* cost allocation provides upfront certainty, explaining that MISO's *ex ante* processes work well and align with past Commission findings regarding the difficulty of supporting new construction without knowing who will pay for it and the importance of working out cost allocation up front, rather than "relitigating it" each time a transmission project is proposed.[2718] MISO TOs do not oppose states voluntarily agreeing to assume cost responsibility for regional transmission projects, which Commission policy already permits via participant funding, but argue that states that want to voluntarily assume cost responsibility for part or all of a transmission project should do so during the transmission planning process (i.e., when considering potential transmission projects) rather than after projects have been selected, so that those approving such projects can know how costs will be allocated.[2719]

1269. New Jersey Commission states that the Commission should not allow transmission providers to use cost allocation methods that rely solely on participant funding, such as PJM's State Agreement Approach. New Jersey Commission explains that such mechanisms are an unjust and unreasonable method for allocating the costs of holistically planned multi-driver projects and portfolios because if transmission projects can only be built if one or more states agree to assume 100% of the resulting costs, more expensive

[2718] MISO TOs Initial Comments at 45-48 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 557, 561; Order No. 1000, 136 FERC ¶ 61,051 at P 499).

[2719] *Id.* at 48-49.

projects or portfolios that maximize net benefits to the transmission planning region will go unbuilt, ultimately driving up system-wide costs.[2720]

1270. Illinois Commission states that *ex ante* approaches should be the primary cost allocation method and include state input and approval, and that the State Agreement Process should only be used for exceptions in which public policy goals fall outside of the scope of Long-Term Regional Transmission Planning. Illinois Commission expresses concerns because it understands the NOPR to state that transmission projects without an *ex ante* cost allocation method would not be funded unless states decide to pay for them through a State Agreement Process, which could create more expensive and siloed transmission planning that does not meet future transmission needs.[2721]

1271. Many commenters express concerns about the optionality of the proposal and argue that it is necessary to have a default *ex ante* cost allocation method where agreement cannot be reached among states and to preserve FPA section 205 filing rights.[2722] Numerous entities support an *ex ante* cost allocation method for Long-Term

[2720] New Jersey Commission Initial Comments at 24.

[2721] Illinois Commission Initial Comments at 16-17.

[2722] ACORE Supplemental Comments at 1; APPA Initial Comments at 6, 44-45; Environmental Groups Supplemental Comments at 2-3; Evergreen Action Initial Comments at 6; Georgia Commission Initial Comments at 9; ITC Initial Comments at 30-31; Massachusetts Attorney General Initial Comments at 18-21; TAPS Initial Comments at 4-5, 24-26; WIRES Initial Comments at 12-13.

Regional Transmission Facilities to be used in the event a State Agreement Process does not result in an agreed-upon cost allocation method.[2723]

1272. For example, Minnesota State Entities contend that an *ex ante* process that allocates costs at least roughly proportional to benefits should be required as the default cost allocation method unless states can agree on an *ex post* cost allocation method within 90 days. Minnesota State Entities also recommend that the Commission require RTOs/ISOs to use postage stamp cost allocation as the default cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities) unless the RTO/ISO can develop an alternate cost allocation method that all affected states agree on within 90 days following RTO/ISO approval.[2724]

1273. PIOs argue that without a default cost allocation method, transmission may be held up in stakeholder processes or by project-by-project litigation to assign costs.[2725] PIOs further caution that the Long-Term Regional Transmission Planning framework is at risk without an *ex ante* cost allocation method because successful negotiation of a State Agreement Process for each transmission project would be unwieldy and create

[2723] Evergreen Action Initial Comments at 6; Exelon Initial Comments at 24, 26; Georgia Commission Initial Comments at 8-9; ITC Initial Comments at 30-31; Massachusetts Attorney General Initial Comments at 18-20, 22-23; MISO Initial Comments at 67-68; Northwest and Intermountain Initial Comments at 18; Pine Gate Initial Comments at 7; PIOs Initial Comments at 67; TAPS Initial Comments at 4-5, 24-25; WIRES Initial Comments at 12-13.

[2724] Minnesota State Entities Initial Comments at 6-7.

[2725] PIOs Initial Comments at 70.

opportunities for free-ridership and obstructionism.[2726] Similarly, AEE argues that relying on a State Agreement Process would not be just and reasonable and likely would stall the transmission planning and cost allocation process.[2727] Acadia Center and CLF assert that where the Commission anticipates that states will fail to agree, it should establish the Long-Term Regional Transmission Cost Allocation Method because, otherwise, ineffective regional transmission planning processes will remain in place.[2728]

1274. SEIA argues that having a default cost allocation method will ensure that transmission that promotes public policy will be built even in the face of disagreement.[2729] R Street states that the Commission should require schedule discipline and a default cost allocation provision for circumstances where states cannot agree, which can include an accelerated Commission-led arbitration process or Commission application of preestablished criteria.[2730]

1275. Georgia Commission asserts that, if Relevant State Entities cannot reach agreement, or if a Relevant State Entity forgoes its opportunity to participate in the State Agreement Process, there should be a default Long-Term Regional Transmission Cost

[2726] *Id.* at 67.

[2727] AEE Reply Comments at 15, 34.

[2728] Acadia Center and CLF Initial Comments at 31 (citing NOPR, 179 FERC ¶ 61,028 at P 310).

[2729] SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

[2730] R Street Initial Comments at 4, 12.

Allocation Method when clear benefits have been identified for a specific transmission facility or portfolio of facilities.[2731]

1276. NYISO does not object to the final rule directing each transmission provider to adopt an *ex ante* cost allocation method for transmission projects selected through Long-Term Regional Transmission Planning for use when an alternative method is not identified in a process that involves the state. NYISO references, as an example, the process cited in the NOPR whereby the New York Commission plays a role in determining the cost allocation method for public policy transmission projects.[2732]

1277. Exelon supports requiring a default *ex ante* cost allocation method that would act as a backstop cost allocation method should the states in a transmission planning region fail to negotiate an alternative cost allocation method for a transmission project or portfolio of projects. Exelon states that failure to reach an agreement on cost allocation should not act as a barrier to needed transmission, and whatever mechanism is developed for receiving state input should not allow one or more states to thwart the goals of other states and stakeholders.[2733]

1278. PPL asserts that the proposal to require a Long-Term Regional Transmission Cost Allocation Method may not solve the problem of states refusing to site transmission

[2731] Georgia Commission Initial Comments at 9.

[2732] NYISO Initial Comments at 49 (citing NOPR, 179 FERC ¶ 61,028 at P 300 & n.500).

[2733] Exelon Initial Comments at 26.

projects where they do not agree on cost allocation, but in some transmission planning regions, it may nevertheless be helpful to have a default cost allocation method.[2734]

1279. Some commenters oppose requiring a default *ex ante* cost allocation method, whether on its own or in combination with a State Agreement Process.[2735] For example, California Commission asserts that the Commission should not mandate an *ex ante* cost allocation method if states cannot agree to a cost allocation method by a certain date.[2736] NRG states that the Commission should focus on voluntary cost allocation and should not use involuntary cost allocation as a substitute to participant-funded interconnection and transmission expansion.[2737] NRG states that it would be unrealistic to expect productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state.[2738]

1280. SERTP Sponsors express concern that requiring state agreements or an *ex ante* cost allocation method before transmission projects are identified is unworkable because regulators in the Southeast will likely insist that the projects first be identified and their benefits and costs determined before the projects are selected and cost allocation

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[2734] PPL Initial Comments at 26.

[2735] *See, e.g.*, Louisiana Commission Initial Comments at 30, 34; NRG Initial Comments at 6; SERTP Sponsors Initial Comments at 28; US Chamber of Commerce Initial Comments at 9-10.

[2736] California Commission Initial Comments at 57.

[2737] NRG Initial Comments at 6, 16.

[2738] *Id.* at 20.

commitments are made.[2739] SERTP Sponsors state that expecting states to accept a cost allocation for transmission projects that they do not support, based on a process they have not chosen, and to which they do not assign value or benefit for retail ratepayers, will not succeed.[2740] Alabama Commission agrees with SERTP Sponsors, stating that the State Agreement Process is a more appropriate and equitable mechanism for allocating the costs of Long-Term Regional Transmission Facilities and should be the sole cost allocation method.[2741] Similarly, US Chamber of Commerce contends that state utility regulators would risk not adequately protecting their constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design and/or benefits of a proposed regional transmission facility.[2742]

1281. EPSA argues that because long-term transmission planning horizons introduce uncertainty risk that customers must bear, cost allocation should be voluntary to the maximum degree possible.[2743] Louisiana Commission opposes proceeding with any transmission projects selected in Long-Term Regional Transmission Planning without the voluntary cost allocation agreement of all impacted states.[2744] Mississippi Commission

[2739] SERTP Sponsors Initial Comments at 3, 28.

[2740] *Id.* at 20.

[2741] Alabama Commission Initial Comments at 9.

[2742] US Chamber of Commerce Initial Comments at 9-10.

[2743] EPSA Initial Comments at 7.

[2744] Louisiana Commission Initial Comments at 17-18, 30.

asserts that the Commission should not require a default *ex ante* cost allocation method because doing so would bias and undermine cost allocation negotiations between states.[2745] Mississippi Commission further argues that the Commission should clarify that state agreement on cost allocation for each transmission facility, or portfolio of facilities, is what is required, not simply involvement in the stakeholder process.[2746]

1282. Xcel opposes a mandated *ex ante* cost allocation method, stating that the industry engaged in more effective long-term transmission planning before Order No. 1000, and that the Commission should give transmission planning regions flexibility to identify potential solutions before identifying the cost allocation for those solutions. In addition, Xcel supports allowing transmission planning regions flexibility to tailor the benefits evaluated to the purpose of the study and project, citing MISO's experience with Long-Range Transmission Planning.[2747] Similarly, Southern states that the Commission should not require an *ex ante* cost allocation process, but if it does, it should adopt the NOPR proposal to allow transmission providers to determine the appropriate benefits.[2748]

1283. Duke asserts that the Commission has provided no support other than pointing to Order No. 1000 as to why Long-Term Regional Transmission Facilities should have a

[2745] Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3.

[2746] Mississippi Commission Initial Comments at 28.

[2747] Xcel Initial Comments at 11-12.

[2748] Southern Initial Comments at 27.

default *ex ante* cost allocation method.[2749] Duke explains that if states disagree with the need, benefits, and cost allocation determined in Commission-jurisdictional transmission planning processes, then states are likely to exercise their jurisdiction over siting and retail cost allocation to thwart development of a Long-Term Regional Transmission Facility.[2750] Duke asks that the Commission clarify that transmission providers may rely solely on a State Agreement Process and are not required to adopt an *ex ante* default Long-Term Regional Transmission Cost Allocation Method.[2751] Duke argues that an *ex post* cost allocation method from a fully litigated Commission proceeding is a more durable solution than a default *ex ante* cost allocation, which may be similarly litigated but also delay siting approvals.[2752]

1284. NESCOE requests that the Commission confirm that if a transmission provider files a State Agreement Process, the transmission provider does not need to file an *ex ante* cost allocation method, and the time period for a state-negotiated alternate cost allocation method would not apply.[2753]

[2749] Duke Initial Comments at 37.

[2750] *Id.* at 3, 35-36.

[2751] *Id.* at 33.

[2752] *Id.* at 3, 36-37.

[2753] NESCOE Initial Comments at 66-67.

### v. Other Cost Allocation Method Proposals

1285. ACEG recommends having a threshold level of voltage or capacity above which a transmission facility would receive regional cost allocation because the benefits of transmission depend directly on having a robust grid capable not only of receiving diverse generation but also of withstanding extreme weather.[2754]

1286. Shell argues that the Commission should be open to non-traditional cost allocation methods, such as the sharing of benefits when a defined benefit/cost ratio threshold is exceeded, to achieve the goal of minimizing first-mover risk. Shell contends that sharing the cost of interconnection-related network upgrades between first movers and subsequent customers is common in the industry and points to ISO-NE, PJM, and MISO as examples of RTOs/ISOs that have revised their OATTs to attempt to address this concern.[2755]

1287. ELCON notes that regardless of the funding mechanism or approved cost allocation method, benefits and risks may change over time as Long-Term Scenarios are updated and needs and solutions are reassessed. Therefore, ELCON states that the three-year reexamination of Long-Term Scenarios should also review cost allocation to ensure that cost causers and willing beneficiaries continue to be assessed the costs of a transmission project over its lifetime.[2756]

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[2754] ACEG Initial Comments at 63.

[2755] Shell Initial Comments at 25-28.

[2756] ELCON Initial Comments at 19.

1288. Xcel proposes that transmission planning regions rely on scenario-based studies that reflect load-serving entity inputs regarding projected generation expansion, expected types and locations of generators, and expected load. Xcel states that the load-serving entities could then adjust their resource plans in light of the resulting costs and benefits. Xcel asserts that this flexibility would result in consensus-based cost allocation tied to the transmission that load-serving entities actually need and would reduce the reluctance to participate in planning as the outcomes could be adjusted to accommodate adjustments in load-serving entity needs and expectations.[2757] Xcel also argues that the Commission should make clear that it is sometimes appropriate to allocate costs to generators, and that transmission access rights allocation should follow cost allocation.[2758]

1289. Certain TDUs argue that the Commission should require any *ex ante* cost allocation method to follow a "beneficiary pays" approach, as opposed to the default, postage stamp load ratio share model.[2759] Certain TDUs claim that the advantages of adopting a beneficiary-pays cost allocation approach are well documented, as the circumstances appropriate for a postage stamp allocation are not necessarily present when allocating costs for Long-Term Regional Transmission Facilities.[2760] R Street similarly

[2757] Xcel Initial Comments at 18.

[2758] *Id.* at 12-13.

[2759] Certain TDUs Initial Comments at 2, 7.

[2760] *Id.* at 8-9.

asserts that the final rule should adhere to the beneficiary-pays principle to allocate the costs of both transmission and interconnection-related network upgrades.[2761]

1290. Cypress Creek contends that where "cost allocation would hamper the use of contingent needs as a driver for multi-value projects," there should be a hybrid approach. Specifically, Cypress Creek suggests allocating costs up to the lesser of: (1) the cost of necessary reliability improvements and (2) the benefit-cost threshold ratio of the multi-value project to the party that needs the improvements. Cypress Creek suggests that the remaining costs be allocated according to multi-value project rules.[2762]

### c. Commission Determination

1291. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities. Specifically, we modify the NOPR proposal to require, instead of just permit, transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Methods for Long-Term Regional Transmission Facilities that are selected. We adopt the NOPR's proposed definition, with modification, of Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected

[2761] R Street Initial Comments at 4, 12.

[2762] Cypress Creek Reply Comments at 12.

in the regional transmission plan for purposes of cost allocation. In addition to this required Long-Term Regional Transmission Cost Allocation Method, we also permit transmission providers to revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process. Any State Agreement Process that transmission providers voluntarily propose to include in their OATTs would not comply with the requirements of this final rule unless Relevant State Entities indicate to the transmission providers that Relevant State Entities have agreed to that process during the Engagement Period (which we discuss further below).[2763]

1292. While we permit transmission providers to include a State Agreement Process in their OATTs to determine cost allocation methods for selected Long-Term Regional Transmission Facilities if the process is agreed to by Relevant State Entities, it cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities. As discussed below, we find that sole reliance on a State Agreement Process to determine a cost allocation method for selected Long-Term Regional Transmission Facilities will not achieve the objectives of this final rule. Additionally, we modify the NOPR proposal to require that, if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if the Commission ultimately finds that the cost allocation method that results from a State

[2763] We discuss the definition of Relevant State Entities below. *See infra* the Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop. In other words, if a Long-Term Regional Transmission Facility or portfolio of such Facilities is selected but a State Agreement Process fails to result in a Commission-accepted cost allocation method for that facility or facilities, then their costs must be allocated through the Long-Term Regional Transmission Cost Allocation Method or Methods that would otherwise apply in the absence of a State Agreement Process (i.e., the backstop Long-Term Regional Transmission Cost Allocation Method).[2764] We clarify that, if the transmission providers have more than one Long-Term Regional Transmission Cost Allocation Method on file, then the method that would otherwise apply to the specific selected Long-Term Regional Transmission Facility would serve as the backstop Long-Term Regional Transmission Cost Allocation Method.

1293. We continue to find that facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[2765] Nevertheless, we find that the requirement for transmission

[2764] For example, transmission providers could file two Long-Term Regional Transmission Cost Allocation Methods, A and B. In this example, Method A would apply only to Long-Term Regional Transmission Facilities under 300 kV. Method B would apply to Long-Term Regional Transmission Facilities at or above 300 kV only if an agreed-upon State Agreement Process fails to result in a Commission-accepted cost allocation method. If, on compliance, transmission providers propose more than one Long-Term Regional Transmission Cost Allocation Method, they must specify to which Long-Term Regional Transmission Facilities each Long-Term Regional Transmission Cost Allocation Method applies.

[2765] NOPR, 179 FERC ¶ 61,028 at P 301.

providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs is necessary because, if transmission providers were to rely solely on a State Agreement Process to determine the cost allocation for Long-Term Regional Transmission Facilities and that process fails to result in agreement, there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs. As a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized. Moreover, transmission providers would likely rely on relatively inefficient or less cost-effective transmission facilities to address the identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further find that reliance solely on a State Agreement Process would suffer from the same flaws that led the Commission to require *ex ante* cost allocation for selected regional transmission facilities in Order No. 1000, as the allocation of transmission costs can be contentious and prone to litigation in multi-state transmission planning regions.[2766] Requiring a Long-Term Regional Transmission

[2766] Order No. 1000, 136 FERC ¶ 61,051 at PP 498-499; *see also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 70 (finding that the Commission reasonably balanced the benefits and claimed burdens of Order No. 1000's reforms in concluding that the requirement that each transmission provider include in its OATT a method(s) for allocating *ex ante* the costs of new regional transmission facilities "would reduce conflicts and 'aid in the development and construction of new transmission'" and allow stakeholders "to determine *ex ante* 'that the benefits associated with [a particular] set of transmission facilities outweigh the costs'" (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 499, 669)).

Cost Allocation Method, even when transmission providers also have a State Agreement Process in effect, provides a level of certainty critical to the development of needed Long-Term Regional Transmission Facilities.

1294. As noted above, the relevant Long-Term Regional Transmission Cost Allocation Method on file would serve as a backstop if the State Agreement Process does not result in a Commission-accepted cost allocation method for the selected Long-Term Regional Transmission Facility or portfolio of such Facilities subject to the State Agreement Process. This outcome could occur for several reasons. For instance, Relevant State Entities may not reach agreement on a cost allocation method pursuant to the terms of a State Agreement Process and the transmission providers may choose not to file any cost allocation method. In another instance, transmission providers may choose not to file a cost allocation method agreed to pursuant to a State Agreement Process and also choose not to file any alternative cost allocation method. And finally, the Commission might not accept a cost allocation method that results from a State Agreement Process and that transmission providers submit to the Commission for filing under FPA section 205 to the extent that it does not satisfy the requirement to allocate costs at least roughly commensurate with estimated benefits or is otherwise unjust or unreasonable.[2767]

[2767] *See PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178, at P 33 (2022) ("In light of the New Jersey state law, the New Jersey [State Agreement Approach] Projects will benefit customers throughout New Jersey, and thus we find that allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects.") (footnote omitted).

1295. In response to NRG's and Mississippi Commission's concerns that a Long-Term Regional Transmission Cost Allocation Method could undermine productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state,[2768] on balance, we find that this possibility is outweighed by the risk that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solution to Long-Term Transmission Needs may not have an associated cost allocation method absent this requirement, and thus would be unlikely to be developed.[2769] As we explain above, the lack of a cost allocation method for selected Long-Term Regional Transmission Facilities would likely result in transmission providers relying on relatively inefficient or less cost-effective transmission facilities to address identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further note that a Long-Term Regional Transmission Cost Allocation Method provides certainty that the costs of Long-Term Regional Transmission Facilities for which a State Agreement Process does not result in a Commission-approved cost allocation method

[2768] Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3; NRG Initial Comments at 20.

[2769] As discussed below in the Requirement that Transmission Providers Seek Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section, we decline to define what constitutes agreement among Relevant State Entities and, as such, we do not require unanimous agreement of Relevant State Entities participating in the Engagement Period on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.

will be allocated in a manner that the Commission has found to be just and reasonable and not unduly discriminatory or preferential.

1296. In response to the arguments by SERTP Sponsors, Alabama Commission, and Louisiana Commission emphasizing the importance of voluntary cost allocation among states,[2770] along with Mississippi Commission's request for clarification that state agreement to a cost allocation method be required for any Long-Term Regional Transmission Facility under this final rule,[2771] we note that Relevant State Entities will have the opportunity to provide their views on cost allocation methods during the Engagement Period, as discussed further below. Following this Engagement Period, Relevant State Entities may agree to, and ask the transmission providers to file, a State Agreement Process, which, if accepted by the Commission, would be the cost allocation process used by the transmission providers in the transmission planning region prior to the use of the relevant Long-Term Regional Transmission Cost Allocation Method as a backstop. Further, as discussed in the Proposals Relating to the Design and Operation of State Agreement Processes section below, during the Engagement Period or State Agreement Process, Relevant State Entities will have an opportunity to agree to and ask transmission providers to file a Long-Term Regional Transmission Cost Allocation

[2770] SERTP Sponsors Initial Comments at 3, 20, 28; Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 17-18, 30.

[2771] Mississippi Commission Initial Comments at 28.

Method. Thus, there are multiple opportunities for Relevant State Entities to voluntarily negotiate a cost allocation method for Long-Term Regional Transmission Facilities.

1297. We find that US Chamber of Commerce's concern, that state utility regulators might fail to protect constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design or benefits of a proposed regional transmission facility, is misplaced.[2772] Any cost allocation method(s) that transmission providers propose, be it as a result of a State Agreement Process or a Long-Term Regional Transmission Cost Allocation Method, must allocate costs in a manner that is at least roughly commensurate with estimated benefits, as discussed further below.[2773] For the same reasons, we disagree with EPSA's contention that, because Long-Term Regional Transmission Planning introduces uncertainty risk that customers must bear, all the relevant cost allocation methods on file should be voluntary.[2774]

1298. We also acknowledge Duke's concerns that a default *ex ante* cost allocation method could delay siting approvals and Xcel's concerns associated with a mandated *ex ante* cost allocation method claiming that the industry engaged more effectively in long-

[2772] US Chamber of Commerce Initial Comments at 9-10.

[2773] *See infra* Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities.

[2774] EPSA Initial Comments at 7.

term transmission planning before Order No. 1000.[2775] We note that another modification to the NOPR proposal that we adopt, as described below, allows State Agreement Processes to occur before, as well as up to six months after, selection of Long-Term Regional Transmission Facilities. This modification helps to address Duke's and Xcel's concerns by providing Relevant State Entities with an opportunity to agree on a cost allocation method for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) after selection. However, we find that, even if such an agreement on a State Agreement Process cost allocation method cannot be achieved, on balance, the greater certainty that *ex ante* cost allocation methods provide to allow the development of Long-Term Regional Transmission Facilities outweighs the concerns that Duke and Xcel express.

1299. Furthermore, we find that allowing the use of a State Agreement Process in addition to a Long-Term Regional Transmission Cost Allocation method will assist in the development of Long-Term Regional Transmission Facilities by taking into account state preferences. SEIA and New Jersey Commission support such flexibility.[2776] We agree with New Jersey Commission that negotiated cost allocation methods may reduce litigation and make it easier to construct needed transmission facilities.[2777] We recognize

[2775] Duke Initial Comments at 36; Xcel Initial Comments at 12.

[2776] New Jersey Commission Initial Comments at 25; SEIA Initial Comments at 24.

[2777] New Jersey Commission Initial Comments at 17.

Dominion's concerns that implementing a State Agreement Process with an *ex ante* approach could lead to delays;[2778] however, we find that both the backstop Long-Term Regional Transmission Cost Allocation Method, combined with a six-month limit after selection for deliberations under any State Agreement Process and the filing of any resulting cost allocation method, as detailed below, should limit such delays.

1300. Next, we adopt the NOPR proposal to apply the cost allocation reforms in this final rule only to new Long-Term Regional Transmission Facilities. We find that this reform does not apply to regional reliability and economic transmission facilities that are selected pursuant to the existing Order No. 1000 regional transmission planning processes. We find, instead, that the existing Commission-accepted *ex ante* regional cost allocation methods adopted pursuant to Order No. 1000 should continue to apply to those regional reliability and economic transmission facilities. We find no basis in the record to conclude that these existing regional cost allocation methods should change, given that this final rule does not alter existing regional reliability and economic transmission planning processes. We believe that this distinction between cost allocation methods for regional reliability and economic transmission projects selected under existing Order No. 1000 regional transmission planning processes and those for new Long-Term Regional Transmission Facilities selected through Long-Term Regional Transmission Planning will prevent the re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of this final rule. In addition, we find

[2778] Dominion Initial Comments at 52.

this distinction to be consistent with our decision not to apply Long-Term Regional Transmission Cost Allocation Methods to transmission facilities other than new Long-Term Regional Transmission Facilities.[2779]

1301. We disagree with PIOs that allowing different cost allocation methods to apply to different regional transmission planning processes is unjust and unreasonable.[2780] We find that because Long-Term Regional Transmission Planning is a more long-term, forward-looking, and comprehensive transmission planning process than existing Order No. 1000 regional transmission planning processes, it is appropriate for transmission providers to consider, following the Engagement Period, whether different cost allocation methods should apply to selected Long-Term Regional Transmission Facilities.

1302. With respect to the potential use of existing regional cost allocation methods as Long-Term Regional Transmission Cost Allocation Methods, as well as assertions that existing cost allocation methods or current existing processes for state involvement in cost allocation decisions could be used for Long-Term Regional Transmission Planning,[2781] we adopt the NOPR proposal that, to the extent transmission providers

[2779] As the Commission noted in the NOPR, the Commission took a similar approach with respect to its cost allocation reforms in Order No. 1000. *See* NOPR, 179 FERC ¶ 61,028 at P 314 n.517 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 565).

[2780] PIOs Initial Comments at 71.

[2781] *See, e.g.*, Ameren Initial Comments at 25-27; APS Initial Comments at 11-12; Avangrid Initial Comments at 28;Dominion Initial Comments at 3, 45; Dominion Reply Comments at 11; MISO Initial Comments at 61, 68; NYISO Initial Comments at 9, 50; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13-14; PJM Initial Comments at 116; PJM States Initial Comments at 11-12; SPP Initial Comments at 28-

believe that their existing cost allocation methods comply with the requirements adopted in this final rule, they may demonstrate in their compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final rule. This approach is consistent with the approach that the Commission took in Order No. 1000, in which the Commission declined commenter requests to decide in the rule itself whether existing cost allocation methods complied with the requirements of Order No. 1000 and instead required transmission providers to demonstrate on compliance that their existing cost allocation methods met the rule's requirements.[2782]

1303. We disagree with PPL's contention that existing regional cost allocation methods accepted by the Commission should be considered the "default." The Commission accepted such *ex ante* regional cost allocation methods based on demonstrations of how they met the six Order No. 1000 regional cost allocation principles. We appreciate, as the Commission has recognized, that some existing regional cost allocation methods are complex, stakeholder-approved constructs and that some are specifically designed to apply to broad portfolios of transmission projects, such as MISO's regional cost allocation method for Multi-Value Projects.[2783] However, as described above, to the

29; Virginia Commission Staff Initial Comments at 6.

[2782] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 565; Order No. 1000-A, 139 FERC ¶ 61,132 at P 747.

[2783] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, at P 434 (2013); *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,059, at P 347 (2013).

extent that transmission providers propose on compliance to use an existing regional cost allocation method as a Long-Term Regional Transmission Cost Allocation Method, the transmission providers must demonstrate that such existing regional cost allocation method, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final rule. We disagree with ITC's contention that the Commission should allow for streamlined compliance plans for transmission providers that already have long-range transmission planning processes; we reiterate that we require transmission providers to submit proposed cost allocation processes on compliance with this rule so that the Commission may evaluate whether those processes comply with the requirements of this final rule.

1304. BP raises a concern that it is not clear, in the case of a multi-value project, whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method as opposed to all of the costs. With the exception of Long-Term Regional Transmission Facilities that one or more Relevant State Entities or interconnection customers agree to voluntarily fund, we clarify that all costs associated with a selected Long-Term Regional Transmission Facility must be allocated using the applicable Long-Term Regional Transmission Cost Allocation Method or Methods, or an applicable Commission-accepted cost allocation method that results from a State Agreement Process.[2784]

[2784] *See supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section. Moreover, in the Local Transmission Planning Inputs in the Regional

1305. In response to requests that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods,[2785] we reiterate that any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent.[2786] Load ratio share, which charges transmission customers in proportion to their use of the transmission system as measured by their relative share of load, is a cost allocation method that may be consistent with the beneficiary-pays approach. The Commission will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits on a fact-specific basis, relying on the record in a given proceeding.

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Transmission Planning Process section below, we provide flexibility to transmission providers to propose a cost allocation method for right-sized replacement transmission facilities.

[2785] *See* Certain TDUs Initial Comments at 2, 7, 8-9; R Street Initial Comments at 4, 12.

[2786] The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87 (citing *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d at 1285); *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 10 ("[T]he principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits."); *ICC v. FERC I*, 576 F.3d at 476 ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.").

1306. In response to commenters that request flexibility in cost allocation,[2787] we believe that the approach to cost allocation for Long-Term Regional Transmission Facilities that we adopt in this final rule provides transmission providers and their stakeholders, and in particular Relevant State Entities, with the flexibility needed to address regional differences. Specifically, we find that the flexibility to submit one *or more* Long-Term Regional Transmission Cost Allocation Methods, as well as the flexibility to submit an additional State Agreement Process, accommodate regional differences.

1307. We decline to adopt additional requirements with respect to cost allocation that we did not propose in the NOPR, such as Shell's request to require coastal transmission providers to explain how their Long-Term Regional Transmission Planning facilitates cost allocation for offshore wind.[2788] We find that the record in this proceeding does not support imposing this or other additional requirements. Regarding certain cost allocation requirements suggested by commenters,[2789] including ACEG's suggestion for implementing a voltage threshold level above which a transmission facility would receive

[2787] *See, e.g.*, Entergy Initial Comments at 29-30; Eversource Initial Comments at 29-30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5-6, 11, 13.

[2788] Shell Initial Comments at 17.

[2789] Cypress Creek Reply Comments at 12; ELCON Initial Comments at 19; R Street Initial Comments at 4, 12; Shell Initial Comments at 25-28; Xcel Initial Comments at 12-13, 18.

regional cost allocation,[2790] we find such proposals to be beyond the scope of this proceeding. The Commission did not make such proposals in the NOPR.

### 2. Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities

#### a. NOPR Proposal

1308. The Commission proposed to require transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2791] The Commission proposed to require transmission providers in each transmission planning region to: (1) explain how the proposed Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof reflects the agreement of Relevant State Entities; or (2) to the extent agreement of Relevant State Entities cannot be obtained, explain the good faith efforts by the relevant transmission provider(s) to seek agreement from such entities before proposing a Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2792]

1309. The Commission proposed to define Relevant State Entities for purposes of the Long-Term Regional Transmission Planning cost allocation requirements as "any state

[2790] ACEG Initial Comments at 63.

[2791] NOPR, 179 FERC ¶ 61,028 at P 303.

[2792] *Id.* P 303.

entity responsible for utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state."[2793]

1310. The Commission proposed to require transmission providers in each transmission planning region to seek to determine whether, for all or a subset of Long-Term Regional Transmission Facilities, Relevant State Entities agree to: (1) a Long-Term Regional Transmission Cost Allocation Method; (2) a State Agreement Process; (3) forgo a role in determining the cost allocation approach for Long-Term Regional Transmission Facilities; or (4) some combination thereof.[2794]

1311. The Commission proposed to afford transmission providers in each transmission planning region flexibility in the process by which they seek agreement from Relevant State Entities and to require transmission providers to provide the state entities with flexibility with regard to defining what constitutes "agreement" among the Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.[2795] Although the Commission proposed to provide transmission providers flexibility in determining what constitutes state agreement, the Commission preliminarily found that, for each state, a single entity should be designated as the voting or

[2793] *Id.* P 304.

[2794] *Id.* P 305.

[2795] *Id.* P 306.

representative entity to avoid confusion or over-representation by a single state in a multi-state voting process.[2796]

1312. Noting that the Relevant State Entities may forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, the Commission proposed that in the event that the Relevant State Entities do so, the Commission would require transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method consistent with the requirements of Order No. 1000, including the prohibition on relying on voluntary agreement among states or participant funding.[2797] The Commission explained that it was not proposing to impose any requirements on states to participate in processes to establish regional cost allocation methods for Long-Term Regional Transmission Facilities.[2798]

**b. Comments**

**i. State Involvement in Cost Allocation Proposals**

1313. Many commenters generally support states having a role negotiating proposed cost allocation methods.[2799] However, some commenters emphasize the importance of

[2796] *Id.* P 304.

[2797] *Id.* P 307.

[2798] *Id.* P 308.

[2799] *See, e.g.*, AEP Initial Comments at 35; Ameren Initial Comments at 25; American Municipal Power Initial Comments at 12; Arizona Commission Initial Comments at 11; Clean Energy Associations Initial Comments at 35; Clean Energy Buyers Initial Comments at 28-29; Clean Energy States Initial Comments at 7; Cross Sector Representatives Supplemental Comments at 1; Duke Initial Comments at 35; ELCON Initial Comments at 17; ISO-NE Initial Comments at 2; Georgia Commission

involving all stakeholders, and not just Relevant State Entities, in this reform. Clean Energy Buyers argue that the Commission should require transmission providers to allow all stakeholders (not just states) to participate in, or at least comment on, the development of the Long-Term Regional Transmission Cost Allocation Method and to recognize the importance of states and all other stakeholders.[2800] Similarly, NEPOOL asserts that state involvement should not diminish the opportunity for stakeholder involvement from all market participants in the electric industry.[2801] APPA asserts that while coordination with state regulators in cost allocation may aid in developing beneficial and cost-effective transmission projects, the perspectives of state regulators on cost allocation should not be elevated above those of other stakeholders.[2802]

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Initial Comments at 8-9; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 28; Joint Consumer Advocates Initial Comments at 13; Maryland Energy Administration Initial Comments at 2; Massachusetts Attorney General Initial Comments at 19; Michigan Commission Initial Comments at 8; MISO Initial Comments at 61; NARUC Initial Comments at 45 (citing NOPR, 179 FERC ¶ 61,028 at PP 303-308), 46; New York Commission and NYSERDA Initial Comments at1; NESCOE Initial Comments at 54; North Carolina Commission and Staff Initial Comments at 2; North Dakota Commission Initial Comments at 4; NRG Initial Comments at 6; NYISO Initial Comments at 49; OMS Initial Comments at 10; PacifiCorp and NV Energy Initial Comments at 15; PIOs Initial Comments at 64; Resale Iowa Initial Comments at 2; US Chamber of Commerce Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 at P 288); Virginia Commission Staff Initial Comments at 2; WIRES Initial Comments at 12.

[2800] Clean Energy Buyers Initial Comments at 29.

[2801] NEPOOL Initial Comments at 9.

[2802] APPA Initial Comments at 42.

1314. Idaho Power states that the Commission should continue to allow flexibility for transmission planning regions to determine the appropriate level of state involvement.[2803] Pacific Northwest Utilities agree, stating that mandating additional state participation could be burdensome and problematic.[2804]

1315. MISO states that the Commission should not extend any state involvement that may be adopted pursuant to the final rule to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final rule.[2805] MISO Coops state that MISO provides a stakeholder forum where states' voices are heard, and the final rule should not diminish stakeholder processes that are effective today.[2806]

1316. Other commenters raise concerns about increased state involvement in cost allocation decisions. For example, Vistra asserts that a prioritized role for states in cost allocation is more likely to create new challenges than ease development, and observes that it may be difficult to coordinate state interests in multi-state transmission planning regions versus single-state transmission planning regions.[2807] Six Cities opposes enhanced roles for Relevant State Entities, suggesting that the proposed reforms represent

[2803] Idaho Power Initial Comments at 10.

[2804] Pacific Northwest Utilities Initial Comments at 13.

[2805] MISO Initial Comments at 71.

[2806] MISO Coops Initial Comments at 2.

[2807] Vistra Initial Comments at 2, 27-28.

neither an appropriate oversight role for states under the FPA, nor a logical extension of Order No. 890 and Order No. 1000 policies.[2808]

1317. ACEG and Georgia Commission agree with the Commission's proposed definition of Relevant State Entities.[2809] ACEG and Dominion also support the proposal to have a single entity designated as the voting representative for the state.[2810] MISO agrees that having a single entity designated for each state and/or applicable jurisdiction as the voting or representative entity for that state/jurisdiction makes sense, but notes that the City of New Orleans is an independent member of OMS separate from the Louisiana Commission and therefore may need to be considered a separate jurisdiction.[2811] Louisiana Commission voices similar concerns.[2812] North Carolina Commission and Staff state that it may be appropriate for different state entities to be designated for different roles,[2813] and Duke asserts that the Commission should clarify that within a state there may be multiple Relevant State Entities.[2814]

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[2808] Six Cities Initial Comments at 7.

[2809] ACEG Initial Comments at 65-66; Georgia Commission Initial Comments at 8.

[2810] ACEG Initial Comments at 65-66; Dominion Initial Comments at 48 n.99.

[2811] MISO Initial Comments at 66.

[2812] Louisiana Commission Initial Comments at 33.

[2813] North Carolina Commission and Staff Initial Comments at 17.

[2814] Duke Initial Comments at 38-39.

1318. Some commenters generally agree with the Commission's proposed definition of Relevant State Entities but request that the definition be expanded or clarified to include self-regulated public power utilities and cooperatives.[2815] TAPS argues that a multi-state voting process, as proposed, could fail to represent public power and cooperatives' interests.[2816] NRECA contends that a more inclusive approach would be to use "relevant electric regulatory authority," which includes a state public utility commission and the governing board of a cooperative or public power utility.[2817] Large Public Power proposes to grant state and municipal utilities representation on a load ratio share basis.[2818]

1319. NASUCA urges the Commission to clarify that where applicable, an approved state cost allocation process should include agreement by a state's utility consumer advocate.[2819] California Energy Commission recommends expanding the definition of Relevant State Entities to include any groups directly or indirectly affected by the construction of a project, such as Native American Tribes,[2820] and NESCOE requests that

[2815] American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42-43 (citing 16 U.S.C. 796(7), (15)); California Municipal Utilities Initial Comments at 17; MISO Coops Initial Comments at 3-4; Six Cities Initial Comments at 10.

[2816] TAPS Initial Comments at 5, 26-27.

[2817] NRECA Initial Comments at 56-57.

[2818] Large Public Power Initial Comments at 41.

[2819] NASUCA Initial Comments at 10-11.

[2820] California Energy Commission Initial Comments at 3.

the definition of Relevant State Entity be amended to accommodate individual transmission planning regions' particular approaches toward state involvement in cost allocation requirements, such as NESCOE managers designated by each New England Governor to represent that state's interests.[2821]

1320. Nevada Commission requests flexibility in the term Relevant State Entity.[2822] New Mexico RETA urges flexibility to account for state involvement of other entities not accounted for in the definition of Relevant State Entities, including state authorities specifically designated to assist in developing new electric transmission facilities (like New Mexico RETA).[2823]

1321. ACEG recommends that the Commission clarify that existing processes, such as SPP's Regional State Committee, MISO's OMS, and ISO-NE's New England States Committee, should be used to determine the Relevant State Entity for each state, unless another process is demonstrated to be superior.[2824]

1322. SERTP Sponsors assert that which Relevant State Entity or Entities would be appropriate for a particular state will be a function of state law.[2825] Pennsylvania

[2821] NESCOE Initial Comments at 57.

[2822] Nevada Commission Initial Comments at 13.

[2823] New Mexico RETA Initial Comments at 8-9 (citing NOPR 179 FERC ¶ 61,028 at P 304).

[2824] ACEG Initial Comments at 66.

[2825] SERTP Sponsors Initial Comments at 28-29.

Commission states that the Commission's proposed definition of Relevant State Entity is imperfect and may result in multiple entities within a single state being a Relevant State Entity, given that the Commission refers to utility regulation or siting authority in the definition, but a state's legislature could have delegated this different authority among different administrative agencies.[2826]

### ii. Requirement to Seek Agreement

1323. Many commenters generally support requiring transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2827]

1324. Avangrid states that state input and collaboration is crucial to the transmission planning process, and that intensive state (and other stakeholder) participation and

[2826] Pennsylvania Commission Initial Comments at 15.

[2827] *See, e.g.*, Acadia Center and CLF Initial Comments at 29-30; Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; Entergy Initial Comments at 29-30; Georgia Commission Initial Comments at 8-9; ISO-NE Initial Comments at 37-38; Louisiana Commission Initial Comments at 30; Michigan Commission Initial Comments at 8; NARUC Initial Comments at 45, 47; Nebraska Commission Initial Comments at 9; NESCOE Initial Comments at 54 (citing NOPR, 179 FERC ¶ 61,028 at PP 303, 305); North Carolina Commission and Staff Initial Comments at 15-16; Ohio Commission Federal Advocate Initial Comments at 11; Pacific Northwest State Agencies Initial Comments at 27; PJM States Initial Comments at 9; SoCal Edison Initial Comments at 3; Southeast PIOs Initial Comments at 55 (citing NOPR, 179 FERC ¶ 61,028 at P 303); US Climate Alliance Initial Comments at 2; WIRES Initial Comments at 12.

consensus-building will help to ensure that transmission will not be overbuilt.[2828] SoCal Edison contends that without agreement among states on the respective benefits and share of related costs, the development of multi-state transmission projects will be nearly non-existent.[2829] PPL supports transmission providers seeking agreement with the states on cost allocation methods, as well as voluntary coordination with states, which PPL argues will make public policy projects more likely to succeed.[2830]

1325. NYISO and ISO-NE support state entities playing a role in determining the cost allocation method for transmission solutions to Long-Term Transmission Needs.[2831] ISO-NE contends that states should be responsible for determining the cost allocation mechanism for policy-based, long-term transmission facility investments because they are uniquely situated to balance the benefits and costs of transmission investments intended to advance their policy goals.[2832]

1326. Mississippi Commission argues that opponents of state involvement in Long-Term Regional Transmission Planning fail to recognize the existing state regulatory role in siting electricity generation, transmission, and distribution facilities.[2833]

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[2828] Avangrid Initial Comments at 28.

[2829] SoCal Edison Initial Comments at 3.

[2830] PPL Initial Comments at 29.

[2831] NYISO Initial Comments at 49; ISO-NE Initial Comments at 37.

[2832] ISO-NE Initial Comments at 37.

[2833] Mississippi Commission Reply Comments at 5.

1327. In addition, some commenters support the agreement of states when determining a Long-Term Regional Transmission Cost Allocation Method. City of New Orleans Council comments that it is essential that state and local regulators agree to any Long-Term Regional Transmission Cost Allocation Method to ensure that the costs borne by retail customers are just and reasonable and not unduly discriminatory or preferential.[2834] SoCal Edison concurs on the necessity for states to reach agreement.[2835] Southern argues that unless state regulators agree to transmission project selection and cost allocation, transmission projects that result from the Commission's proposed Long-Term Regional Transmission Planning are not likely to come to fruition.[2836]

#### iii. Seek Changes to, Raise Concerns About, or Oppose the Requirement to Seek Agreement

1328. Some commenters support requiring transmission providers to seek agreement with Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or a combination thereof, but propose changes to the proposal. For example, Kentucky Commission Chair Chandler asserts that states should not be permanently bound by their agreement on an initial cost allocation method, and that the Commission should clarify that transmission providers should continue to seek agreement from states prior to seeking Commission approval for any

[2834] City of New Orleans Council Initial Comments at 9.

[2835] SoCal Edison Initial Comments at 3, 13.

[2836] Southern Initial Comments at 9-10.

change to the cost allocation method filed on compliance.[2837] Similarly, PJM States request that the Commission require transmission providers to show they sought support of retail regulators for subsequent revisions of the initial cost allocation method.[2838] PJM States ask that the Commission also require a regular check-in with retail regulators regarding the appropriateness of any existing cost allocation method.[2839]

1329. Resale Iowa states that it is concerned that large, multi-state transmission projects may increase the number of participants to the point that agreement is difficult to achieve and suggests that multi-state organizations may provide an avenue for conveying state interests to transmission providers and reaching agreements.[2840] DC and MD Offices of People's Counsel support giving state entities a "defined and expansive role" in the regional transmission selection and cost allocation processes but argue that this role must be anchored by their ability to timely agree on cost allocation.[2841]

1330. Other commenters offered modified versions of the NOPR proposal. California Commission states that the Commission should require that transmission providers use their FPA section 205 filing rights to submit the *ex post* cost allocation method (and/or combined method) agreed on by states even if the transmission providers in a

[2837] Kentucky Commission Chair Chandler Initial Comments at 3.

[2838] PJM States Initial Comments at 10.

[2839] *Id.* at 10-11.

[2840] Resale Iowa Initial Comments at 2, 12.

[2841] DC and MD Offices of People's Counsel Initial Comments at 37.

transmission planning region determine that they will propose an *ex ante* cost allocation method for the Commission's consideration.[2842]

1331. Dominion states that it may be nearly impossible to achieve state consensus in multi-state RTOs/ISOs and that if the states in a transmission planning region are unable to agree on the proper cost allocation method, the transmission providers should be able to file their own proposed cost allocation method.[2843]

1332. Some commenters oppose the proposed requirement to seek agreement. For example, Minnesota State Entities state that the term "seeking state agreement" is too vague and may lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans. Minnesota State Entities suggest replacing the term "seeking state agreement" with "take into account" or "evaluating and incorporating" state concerns in the regional cost allocation approaches as regularly happens at MISO and other RTOs/ISOs.[2844] MISO Coops state that the NOPR proposal for a transmission provider to seek agreement with Relevant State Entities is unnecessary and would be inferior to current stakeholder processes, setting up redundant and potentially conflicted processes.[2845]

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[2842] California Commission Initial Comments at 55-56.

[2843] Dominion Initial Comments at 48.

[2844] Minnesota State Entities Initial Comments at 7.

[2845] MISO Coops Initial Comments at 4.

1333. Kansas Commission questions the necessity of a requirement to seek the agreement of Relevant State Entities within a transmission planning region like SPP, where the SPP Regional State Committee has substantial influence over cost allocation.[2846] PacifiCorp and NV Energy oppose a requirement for transmission providers to seek state agreement on a cost allocation method, contending that such a requirement would add complexity and significant process and time.[2847] NRG states that under the proposal for transmission providers to seek the agreement of Relevant State Entities on cost allocation, customers that ultimately pay the cost of Long-Term Regional Transmission Facilities are left out of the cost allocation process. NRG suggests that the proposal be limited to transmission projects included in regional transmission plans that would not exist but for state public policy, as it is reasonable for states to fill this negotiating role as described in the NOPR.[2848]

1334. MISO TOs contend that MISO and MISO TOs have already afforded opportunities for states to participate in the development of cost allocation methods,[2849] and argue that the NOPR requirements as drafted are unnecessary for the MISO region.[2850] MISO TOs argue that the Commission should find compelling the fact that

[2846] Kansas Commission Initial Comments at 15-16.

[2847] PacifiCorp and NV Energy Initial Comments at 16.

[2848] NRG Initial Comments at 19.

[2849] MISO TOs Initial Comments at 45.

[2850] MISO TOs Reply Comments at 3.

MISO, MISO TOs, and OMS all support the existing collaborative process for cost allocation in MISO, and request that the Commission not impose changes on this process, but instead afford regional flexibility.[2851]

1335. MISO TOs disagree with commenters that argue that the NOPR provided too much discretion and deference to transmission providers,[2852] or that the Commission should require transmission providers to add a mechanism that ensures compliance with the requirements to include Relevant State Entities in cost allocation.[2853] MISO TOs state that these proposals are contrary to the FPA because they attempt to usurp the statutory rights of transmission providers and point to similar sentiments expressed by the Indicated PJM TOs.[2854]

#### iv. Requirements Associated with Seeking Agreement of Relevant State Entities

1336. ACEG, ACORE, and NESCOE support the NOPR proposal to require transmission providers to demonstrate their good faith efforts to seek agreement from Relevant State Entities before proposing a Long-Term Regional Transmission Cost

[2851] *Id.* at 9 (citing APS Initial Comments at 10-11; MISO Initial Comments at 55-69; MISO TOs Initial Comments at 41-45; OMS Initial Comments at 10-13).

[2852] *Id.* at 4 (citing California Commission Initial Comments at 51-54).

[2853] *Id.* at 4-5 (citing NARUC Initial Comments at 49; NESCOE Initial Comments at 16-19, 46 (requesting that the Commission either require codification of states' roles for cost allocation of long-term regional transmission facilities in OATTs or require explanation following consultation with states of a different approach)).

[2854] *Id.* at 5, 8 (citing Indicated PJM TOs Initial Comments at 23).

Allocation Method, State Agreement Process, or combination thereof.[2855] AEE states that the final rule should better define what constitutes "good faith effort" to seek agreement on cost allocation from states, including the Commission's minimum expectations concerning the time that transmission providers must allow states to reach agreement, the need to hold meetings, and related topics.[2856] OMS, on the other hand, urges the Commission to not require a formal process in which transmission providers must demonstrate how they sought the agreement of state entities.[2857]

1337. NARUC recommends that the Commission require, at a minimum, that transmission providers: (1) communicate with Relevant State Entities promptly in a manner that is reasonably calculated to be received by the Relevant State Entities and (2) establish a forum for negotiation that enables robust participation from Relevant State Entities and transmission providers.[2858] PacifiCorp and NV Energy urge the Commission to clarify that a transmission provider's obligation under any final rule is only to provide state regulators an opportunity to participate in the process of establishing a cost allocation method, should they so choose.[2859] NESCOE asserts that the Commission

[2855] ACEG Initial Comments at 65; ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NESCOE Initial Comments at 59 (citing NOPR, 179 FERC ¶ 61,028 at P 308).

[2856] AEE Initial Comments at 33-34.

[2857] OMS Initial Comments at 11.

[2858] NARUC Initial Comments at 44.

[2859] PacifiCorp and NV Energy Initial Comments at 17.

should require transmission providers to afford Relevant State Entities sufficient time to agree on a cost allocation approach. NESCOE advocates for the Commission to give states six months from the effective date of a final rule to agree on a cost allocation method, which NESCOE argues is needed due to the complexity involved.[2860]

1338. Some commenters support the NOPR proposal to provide states flexibility in determining what constitutes agreement among Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.[2861] Alabama Commission contends that the Commission should not establish any specific timeline for negotiation to allow sufficient time for states to reach such agreement.[2862] In contrast, ACEG argues that there must be a firm time frame for any negotiations, because allowing Relevant State Entities more time to reach agreement could unnecessarily delay the process.[2863] Likewise, Pine Gate and PIOs support requiring a firm deadline, arguing that

[2860] NESCOE Initial Comments at 60.

[2861] *See, e.g.*, ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); Georgia Commission Initial Comments at 8; Massachusetts Attorney General Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NARUC Initial Comments at 47-48 (citing NOPR, 179 FERC ¶ 61,028 at P 306); Nebraska Commission Initial Comments at 10; NESCOE Initial Comments at 58; Pacific Northwest State Agencies Initial Comments at 24-25 (citing NOPR, 179 FERC ¶ 61,028 at PP 309, 318).

[2862] Alabama Commission Initial Comments at 9.

[2863] ACEG Initial Comments at 64-65.

absent such a requirement, a single state or a handful of states could significantly delay transmission development.[2864]

1339. While ACEG supports the NOPR proposal, ACEG cautions that this flexibility should not grant states veto power over the agreement.[2865] Similarly, PJM States argue that the Commission should not require unanimity in determining an initial Long-Term Regional Transmission Cost Allocation Method, and instead, retain the proposal in the NOPR to allow states to determine how they will come to agreement on a Long-Term Regional Transmission Facility cost allocation approach.[2866] New Jersey Commission further asserts that the Commission must ensure that transmission providers cannot unilaterally veto proposals that result from states' negotiations on a cost allocation approach.[2867]

1340. Nebraska Commission asserts that the Commission should allow RTOs/ISOs that have an existing decision-making process that includes state entity participation to continue using it, citing SPP's Regional State Committee and MISO's OMS as well-established processes developed over many years with stakeholder input. Nebraska Commission adds that providing flexibility in this process for transmission providers

[2864] Pine Gate Initial Comments at 46; PIOs Initial Comments at 69-70.

[2865] ACEG Initial Comments at 66.

[2866] PJM States Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 304, 319).

[2867] New Jersey Commission Initial Comments at 17.

would be the least disruptive and most useful approach.[2868] Relatedly, ACORE states that where agreements on cost allocation have already been reached with state entities for transmission projects with multiple benefits, the Commission should not require transmission providers to revisit those agreements.[2869]

1341. ISO-NE also supports the Commission's proposal to afford transmission providers flexibility in determining what constitutes state agreement, as well as the process by which they seek agreement from the states. ISO-NE argues that if state agreement cannot be reached, the Commission should allow the transmission planning region to develop a fallback cost allocation method for use in the event that the states agree to move forward with a long-term transmission facility to advance public policy, but do not agree on a cost allocation method. ISO-NE requests that a final rule be clear that the OATT will be the means by which the states will communicate the agreed cost allocation method to the transmission provider, but the OATT should not dictate the process by which states engage to achieve consensus.[2870]

1342. Some commenters favor mandating what constitutes agreement among Relevant State Entities. Pine Gate states that the Commission should establish a minimum set of criteria outlining when it will consider there to be such agreement. Pine Gate also asks for clarification as to whether unanimity is necessary for states to reach agreement on a

[2868] Nebraska Commission Initial Comments at 10.

[2869] ACORE Initial Comments at 18 (NOPR, 179 FERC ¶ 61,028 at P 314).

[2870] ISO-NE Initial Comments at 37-38.

cost allocation method.[2871] Similarly, AEE requests additional guidance on what it means for states to "agree" to cost allocation approaches.[2872] Shell states that an OATT mechanism that clearly delineates the process and timing for state input will facilitate the participation of Relevant States Entities. However, Shell further states, the OATT provision could provide flexibility for stakeholders to identify the relevant agency for each state as the voting entity for cost allocation decisions.[2873]

1343. Acadia Center and CLF assert that the Commission should clarify that states within a given transmission planning region need not unanimously agree on a cost allocation method and can define agreement as necessary when a majority of states in such region approve a cost allocation method for transmission facilities.[2874] Acadia Center and CLF explain that such an approach is consistent with NESCOE's memorandum of understanding in ISO-NE,[2875] and similarly, New England for Offshore Wind argues that the Commission should not require agreement to be unanimous among states in a multi-state transmission planning region.[2876]

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[2871] Pine Gate Initial Comments at 45-46.

[2872] AEE Initial Comments at 32-33 (citing NOPR, 179 FERC ¶ 61,028 at P 306).

[2873] Shell Initial Comments at 16-17.

[2874] Acadia Center and CLF Initial Comments at 30.

[2875] *Id.* at 31 (citing Memorandum of Understanding Among ISO-NE, NEPOOL, and NESCOE, at 3, 9 (Nov. 21, 2007), https://www.iso-ne.com/static-assets/documents/regulatory/part_agree/mou_final.pdf).

[2876] New England for Offshore Wind Initial Comments at 4-5.

1344. PIOs also argue that the Commission should not require that states in a particular transmission planning region unanimously approve an *ex ante* cost allocation method. PIOs assert, rather, that the Commission should allow transmission providers to adopt a cost allocation method that is otherwise just and reasonable with agreement among a majority of states. PIOs state that each RTO/ISO has an organization of states that operates as a committee and that most of these committees require a simple majority vote (for example, the SPP Regional State Committee, OPSI, and OMS) and that the experience with the RTO/ISO regional state committees can be extrapolated and applied to the non-RTO/ISO transmission planning regions as well.[2877] Pattern Energy proposes that a reasonable threshold for "agreement" would be for one-half of the Relevant State Entities to agree to the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2878]

1345. In contrast, Southeast PIOs propose that state agreement should require unanimous acceptance by the states in the relevant transmission planning region. Southeast PIOs state that in the event transmission providers are unable to achieve unanimity, the Commission could presumptively impose the cost allocation mechanism approved by a plurality of the transmission planning region's states.[2879]

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[2877] PIOs Initial Comments at 66-67.

[2878] Pattern Energy Initial Comments at 19.

[2879] Southeast PIOs Initial Comments at 56.

### v. Outcome if Relevant State Entities Forgo a Role in Determining a Long-Term Regional Transmission Cost Allocation Method

1346. Some commenters support the Commission's proposal that, in the event that states forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, transmission providers must propose a Long-Term Regional Transmission Cost Allocation Method.[2880]

### vi. Outcome if Relevant State Entities Fail to Reach Agreement on a Cost Allocation Method

1347. Several commenters agree with the proposal that, in the event that Relevant State Entities fail to reach an agreement on a cost allocation method, transmission providers must file a cost allocation method with the Commission.[2881] NARUC recommends that if Relevant State Entities are unable to reach agreement on cost allocation, the Commission should require transmission providers to file changes to their OATTs that reflect as much consensus as was reached.[2882]

1348. PIOs state that when cost allocation disputes occur, the Commission could use its authority to convene a joint board with affected states to consider issues and make

[2880] MISO Initial Comments at 67; NESCOE Initial Comments at 59; Pennsylvania Commission Initial Comments at 13; PIOs Initial Comments at 67.

[2881] ACEG Initial Comments at 64; Entergy Initial Comments at 31; Pacific Northwest State Agencies Initial Comments at 29; PacifiCorp and NV Energy Initial Comments at 16; Pattern Energy Initial Comments at 19; TAPS Initial Comments at 4, 23-24.

[2882] NARUC Initial Comments at 48-49.

decisions.[2883] PIOs further state that if states cannot agree to an *ex ante* cost allocation method by the compliance deadline for the final rule, the Commission should institute a default cost allocation method.[2884]

1349. Similarly, Eversource and Vermont Electric and Vermont Transco state that when Relevant State Entities fail to agree on a cost allocation method, the Commission should establish the Long-Term Regional Transmission Cost Allocation Method.[2885] To improve transparency and certainty, Clean Energy Associations state that the Commission should establish a cost allocation method upfront for situations where "state concurrence on either an *ex ante* or *ex post* approach" cannot be reached, submitting that a 90-day period would be reasonable for the Commission to determine a cost allocation method in the absence of state concurrence on either type of approach.[2886]

1350. In contrast, Pacific Northwest State Agencies oppose the Commission establishing a Long-Term Regional Transmission Cost Allocation Method on its own initiative.[2887] NESCOE states that having the transmission provider file a cost allocation method when states cannot agree is preferable to the Commission establishing the cost allocation

[2883] PIOs Initial Comments at 67 (citing 16 U.S.C. 824h; 18 CFR 385.1304).

[2884] *Id.* at 69.

[2885] Eversource Initial Comments at 30 (citing NOPR, 179 FERC ¶ 61,028 at P 310 (citation omitted)); Vermont Electric and Vermont Transco Initial Comments at 4.

[2886] Clean Energy Associations Initial Comments at 36.

[2887] Pacific Northwest State Agencies Initial Comments at 29.

method. Specifically, NESCOE asserts that a more appropriate role for the Commission is to establish general principles under a final rule and evaluate compliance filings made by transmission providers (or subsequent FPA section 205 proposals down the road) for adherence to those principles.[2888]

1351. NESCOE further suggests that if the states cannot reach agreement within the first four months after the effective date of a final rule, they should be provided the opportunity to request that the Commission appoint one or more senior staff members to facilitate agreement.[2889]

1352. In contrast, where agreement is not reached in the established timeframe, ACEG states that the Commission should permit transmission providers to explain their good faith efforts undertaken to seek agreement.[2890]

1353. Clean Energy Associations, some state legislators, and some US Senators state that the final rule should provide clarity around how disagreements among states or transmission providers regarding cost allocation will be handled.[2891] Clean Energy Associations recommend, and Ørsted agrees, that in the absence of such agreement, the

[2888] NESCOE Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

[2889] *Id.* at 60.

[2890] ACEG Initial Comments at 64-65.

[2891] Clean Energy Associations Initial Comments at 35-36 (citing NOPR, 179 FERC ¶ 61,028 at P 310); Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; US Senators Supplemental Comments at 2.

Commission should require cost allocation to track the identified and quantifiable benefits of Long-Term Regional Transmission Facilities.[2892] Senator Schumer supports providing guidance when there is no state agreement on cost allocation to prevent state vetoes of cost allocation methods and to prevent states being incentivized to free ride on transmission planning and avoid costs.[2893]

### c. Commission Determination

1354. We decline to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Instead, we modify the NOPR proposal to establish a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.

[2892] Clean Energy Associations Initial Comments at 35-36; Ørsted Initial Comments at 9.

[2893] Senator Schumer Supplemental Comments at 2.

1355. We adopt the NOPR proposal, with modification, to define Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.[2894] We modify the definition to add the word "electric" before "utility regulation" to make clear that Relevant State Entities are those state agencies responsible for *electric* utility regulation, and not other types of utility regulation.

1356. Specifically, with respect to the mechanics of the Engagement Period, we require that transmission providers in each transmission planning region provide notice, such as on its OASIS page or public website, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period. The notice must include contact information for a single point of contact in the transmission planning region that the Relevant State Entities can use to communicate any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement.[2895] Such deadline must be no earlier than the end date of the Engagement Period.

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[2894] *See* NOPR, 179 FERC ¶ 61,028 at P 304.

[2895] As we discuss above in the Cost Allocation for Long-Term Regional Transmission Facilities section, Relevant State Entities must indicate that they have agreed to any State Agreement Process in order for any such process to be eligible for acceptance by the Commission in compliance with this final rule. Consistent with FPA section 205, however, transmission providers have the right to not file a State Agreement Process. *See infra* Filing Rights Under the FPA section for a further discussion. *See also*

1357. We require transmission providers in each transmission planning region to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period, consistent with NARUC's suggestion.[2896] We require transmission providers to explain on compliance how they complied with the requirement to establish and provide notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as how they complied with the requirement to provide a forum for such negotiation. In response to commenters that argue that their transmission planning regions already have mechanisms for state involvement in regional transmission planning and cost allocation processes,[2897] we note that Relevant State Entities can choose to use existing mechanisms for state involvement in regional transmission planning and cost allocation processes, such as the SPP Regional State Committee and the Organization of MISO States, to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process. However, even where Relevant State Entities indicate to the transmission providers in a transmission planning region that they will use such existing mechanisms as the forum for their negotiations, transmission providers must still demonstrate on compliance that, consistent with the requirements of

*Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (finding that the Commission may not require utility owners to give up statutory rights under FPA section 205).

[2896] NARUC Initial Comments at 44.

[2897] *E.g.*, MISO Initial Comments at 61; SPP Initial Comments at 28-30; PJM Initial Comments at 116.

this final rule, they provided notice of the starting and end dates for the six-month time period and posted contact information that Relevant State Entities may use to communicate with transmission providers about their proposed Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process to which Relevant State Entities have agreed, as well as a deadline for communicating such agreement.

1358. As described above, we adopt a six-month time period for the Engagement Period. While the NOPR did not propose a particular time period for the Engagement Period, we believe that the six-month time period that we adopt here balances the need to ensure that Relevant State Entities have sufficient time to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process if they choose to do so, particularly given the complexity that such negotiations may involve, with the need to ensure that an extended Engagement Period does not unduly delay the implementation of the reforms that we adopt in this final rule. We appreciate Alabama Commission's concerns about establishing a specific time period for negotiations, but we find that limiting the Engagement Period to six months is necessary to ensure that transmission providers have sufficient time to prepare their compliance filings in advance of the compliance deadlines that we establish in this final rule.[2898]

1359. If the Relevant State Entities participating in an Engagement Period agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement

[2898] Alabama Commission Initial Comments at 9.

Process and provide that Method or Methods and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement, which must be no earlier than the end date of the Engagement Period, the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. We note, however, that the ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.

1360. We do not adopt the NOPR proposal that for each state, a single entity should be designated as the voting or representative entity. In light of the fact that we now require an Engagement Period, rather than mandating that transmission providers seek agreement with Relevant Sate Entities on the relevant cost allocation method or process, we decline to adopt a requirement that a single entity be designated for each state as the voting or representative entity. In addition, we decline to define what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement during the Engagement Period. Instead, we leave such matters, including whether to use existing state processes as a forum for negotiations, as Nebraska Commission advocates,[2899] to the Relevant State Entities participating in the Engagement Period to determine. The requirements that we establish in the final rule are that transmission providers must demonstrate on compliance that they

[2899] Nebraska Commission Initial Comments at 10.

established and provided notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as that they provided a forum for such negotiation.

1361. Likewise, we do not agree with commenters, like Pine Gate, that the Commission should establish a minimum set of criteria for a state agreement.[2900] Instead, we find that the criteria for agreement are more appropriately determined by the Relevant State Entities participating in the Engagement Period. Whether agreement should require a majority,[2901] a threshold of one-half of the participating Relevant State Entities,[2902] or unanimity (Southeast PIOs)[2903] is a decision for the Relevant State Entities participating in the Engagement Period. We find that this approach also addresses many of the issues commenters raised relating to the potential difficulties associated with mandating agreement on a Long-Term Regional Transmission Cost Allocation Method(s), including ACEG's concern that requiring agreement could lead to certain states holding a veto power over the agreement.[2904] Moreover, we reiterate that, as discussed in the Cost Allocation Methods for Long-Term Regional Transmission Facilities section above,

[2900] Pine Gate Initial Comments at 45-46.

[2901] Acadia Center and CLF Initial Comments at 30; PIOs Initial Comments at 66-67.

[2902] Pattern Energy Initial Comments at 19.

[2903] Southeast PIOs Initial Comments at 56.

[2904] ACEG Initial Comments at 66.

transmission providers must file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final rule; a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities.

1362. We acknowledge commenters' support of the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities regarding the relevant cost allocation method or process to be applied to Long-Term Regional Transmission Facilities, based upon the rationale that states play a critical role in transmission planning, and that facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings. [2905] We find that requiring an Engagement Period provides the same opportunity for robust engagement in the cost allocation process as the NOPR proposal, and thus has the potential to achieve the same important benefits, but will reduce the practical challenges associated with requiring transmission providers to seek the agreement of Relevant State Entities.[2906]

1363. While we agree with commenters regarding the value of an opportunity for state engagement regarding cost allocation, and accordingly adopt the Engagement Period, we

[2905] NOPR, 179 FERC ¶ 61,028 at P 301 (footnote omitted); *see, e.g.*, Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; SoCal Edison Initial Comments at 3, 13.

[2906] *See, e.g.*, Minnesota State Entities Initial Comments at 7 (claiming that a requirement to seek agreement could lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans).

do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive.[2907] Transmission providers retain the ultimate responsibility for transmission planning, and, as discussed below, they have FPA section 205 filing rights to propose tariff changes to rates, which the Commission cannot deprive them of via this final rule.[2908] The Commission has a statutory responsibility to review such filings to ensure that any proposed cost allocation is just and reasonable and not unduly discriminatory or preferential. Robust state engagement can valuably inform a cost allocation approach, but it cannot supplant these distinct, statutorily defined roles.

1364. We appreciate that certain commenters request to expand or clarify the NOPR's proposed definition of Relevant State Entities to include additional entities, or to otherwise allow the participation of other entities in the Engagement Period. For example, some commenters request that the definition be expanded to include Native American Tribes, self-regulated public power utilities, cooperatives, non-jurisdictional transmission providers, customer interests, state utility consumer advocates, non-traditional state agencies, and local regulatory bodies.[2909] However, we decline to expand

[2907] *See, e.g.*, Southern Initial Comments at 9.

[2908] *See, e.g.*, *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9 (noting that section 205 of the FPA gives utilities the right to file rates and terms for services rendered, and finding that the Commission cannot require that utility owners give up those statutory rights under FPA section 205); *infra* Filing Rights Under the FPA section.

[2909] American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42-43 (citing 16 U.S.C. 796(7), (15)); California Energy Commission Initial Comments at 3; California Municipal Utilities Initial Comments at 16-17; Large Public Power Initial Comments at 41; MISO Coops Initial Comments at 3-4; Northwest and Intermountain Initial Comments at 18; NRECA Initial Comments at 56-57; Six Cities

participation in the Engagement Period beyond Relevant State Entities. As discussed in the NOPR, "regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders – in particular, a state regulator responsible for permitting transmission facilities – do not perceive the regional transmission facilities' value as commensurate with their costs."[2910] The Commission further stated, and we continue to believe, that "providing state regulators with a formal opportunity to develop a cost allocation method for [Long-Term Regional Transmission Facilities] selected through Long-Term Regional Transmission Planning could help increase stakeholder – and state – support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable Commission-jurisdictional rates."[2911] For the same reasons, we also do not find it necessary to allow other stakeholders to participate in the Engagement Period, as some commenters advocate.[2912] In response to Nevada Commission's request for additional flexibility in the term Relevant State Entity,[2913] and NESCOE's request to amend the definition to accommodate individual transmission planning regions' particular approaches to cost allocation requirements, we find that the

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Initial Comments at 10.

[2910] NOPR, 179 FERC ¶ 61,028 at P 297 (footnote omitted).

[2911] *Id.* at P 299.

[2912] *See, e.g.*, Clean Energy Buyers Initial Comments at 29.

[2913] Nevada Commission Initial Comments at 13.

definition of Relevant State Entities, as amended, recognizes the important role of states while providing sufficient regional flexibility for effective Engagement Period participation.[2914]

1365. We acknowledge SERTP Sponsors' concern that determining which Relevant State Entities would be appropriate to participate will be a function of state law,[2915] and, as Pennsylvania Commission points out, a state's legislature could have divided utility regulation and siting authority among different state agencies.[2916] In response to these concerns and Duke's clarification request,[2917] and as we note above, we provide flexibility on how Relevant State Entities reach agreement during the Engagement Period and decline to adopt the requirement that, for each state, a single entity should be designated as the voting or representative entity. We clarify that there may be multiple Relevant State Entities for each state, so long as each Relevant State Entity meets the definition as provided in this final rule. As noted above, the definition of Relevant State Entity provides sufficient flexibility for participation in the Engagement Period.

[2914] NESCOE Initial Comments at 57. As discussed below in the Proposals Relating to the Design and Operation of State Agreement Process section, we will permit other participants beyond Relevant State Entities to participate in the State Agreement Process, if agreed to by Relevant State Entities.

[2915] SERTP Sponsors Initial Comments at 28-29.

[2916] Pennsylvania Commission Initial Comments at 15.

[2917] Duke Initial Comments at 38-39.

1366. We find that the decision to modify the NOPR proposal, which would have required transmission providers to seek agreement of Relevant State Entities, to instead require transmission providers to establish a six-month Engagement Period largely moots several other reforms proposed in the NOPR. We therefore decline to adopt other proposed reforms that detailed the requirements associated with transmission providers seeking agreement of Relevant State Entities.

1367. We note that transmission providers' compliance with this final rule is not contingent on Relevant State Entities' participation in the Engagement Period. Transmission providers' compliance with this final rule is also not contingent on Relevant State Entities reaching an agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. If Relevant State Entities fail to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, transmission providers must still file one or more Long-Term Regional Transmission Cost Allocation Methods in compliance with this final rule. We acknowledge commenters' recommendations on action we should take in the event Relevant State Entities fail to reach an agreement. But we decline to convene a joint board of affected states if Relevant State Entities cannot agree, as suggested by PIOs,[2918] and the Commission will not establish a Long-Term Regional Transmission Cost Allocation Method in the event that Relevant State Entities fail to

[2918] PIOs Initial Comments at 67.

agree, as proposed by Eversource and Vermont Electric and Vermont Transco.[2919] Because this final rule requires transmission providers to file a Long-Term Regional Transmission Cost Allocation Method, these additional steps are not necessary to ensure that there will be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1368. Furthermore, we decline to adopt NARUC's request that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Transmission Facilities.[2920] This final rule requires that transmission providers establish a one-time Engagement Period for purposes of compliance with this final rule; transmission providers may file subsequent changes to their cost allocation methods for Long-Term Regional Transmission Facilities pursuant to their filing rights under FPA section 205, at which point parties may file comments in support of or protests to such filings. We note, however, that some RTOs/ISOs have stakeholder processes that occur prior to making FPA section 205 filings on cost allocation, which could provide an additional opportunity for stakeholders to present their views on a proposed cost allocation method for Long-Term Regional Transmission Facilities. We decline to require future Engagement Periods beyond the initial Engagement Period but note that

[2919] Eversource Initial Comments at 30; Vermont Electric and Vermont Transco Initial Comments at 4.

[2920] NARUC Initial Comments at 49-50.

transmission providers may hold future Engagement Periods if they believe such periods would be beneficial.

### 3. Proposals Relating to the Design and Operation of State Agreement Processes

#### a. NOPR Proposal

1369. The Commission preliminarily found that a State Agreement Process by which one or more Relevant State Entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) after they are selected may be a just and reasonable approach to cost allocation for such regional transmission facilities and that the State Agreement Process could apply to all Long-Term Regional Transmission Facilities or only to a subset thereof.[2921]

1370. The Commission proposed to require that if the Relevant State Entities agree on a State Agreement Process, then the transmission providers in each transmission planning region must describe in their OATTs the process by which Relevant State Entities would reach voluntary agreement pursuant to that State Agreement Process regarding the cost allocation for Long-Term Regional Transmission Facilities, including the timeline for such processes. The Commission noted that, for example, the transmission providers in each transmission planning region could specify in their OATTs the procedures by which such voluntary agreements by the Relevant State Entities may be filed with the Commission for consideration under FPA section 205. The Commission proposed to

[2921] NOPR, 179 FERC ¶ 61,028 at P 311.

require that such procedures include a process by which Relevant State Entities would agree to funding contributions and the mechanism by which such costs would be allocated (e.g., through a *pro forma* contract).[2922]

**b. Comments**

**i. Support for State Agreement Process**

1371. Several commenters generally support the Commission's proposal to permit transmission providers to submit a State Agreement Process as a Long-Term Regional Transmission Cost Allocation Method.[2923] NARUC supports allowing Relevant State Entities to agree to using the State Agreement Process to commit their customers to fund all or a portion of the costs of a Long-Term Regional Transmission Facility as a means of meeting a transmission planning region's selection criteria.[2924]

1372. Mississippi Commission contends that the State Agreement Process will likely promote transmission construction because authority over transmission construction and

[2922] *Id.* P 313.

[2923] American Municipal Power Initial Comments at 12; City of New Orleans Initial Comments at 9-10; Entergy Initial Comments at 34-35; Georgia Commission Initial Comments at 8-9; ISO-NE Initial Comments at 37; ITC Initial Comments at 28-32; Louisiana Commission Initial Comments at 33: Mississippi Commission Initial Comments at 6; NARUC Initial Comments at 53-54; NESCOE Initial Comments at 62; North Carolina Commission and Staff Initial Comments at 15-16; Ohio Commission Federal Advocate Initial Comments at 12; Pacific Northwest State Agencies Initial Comments at 27, Pennsylvania Commission Initial Comments at 12-13; PIOs Initial Comments at 64; TAPS Initial Comments at 4-5, 24-26; Resale Iowa Initial Comments at 2, 12; Southern Initial Comments at 9; SERTP Sponsors Initial Comments at 28-29.

[2924] NARUC Initial Comments at 53-54 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

siting rests with the states.[2925] Mississippi Commission asserts that the State Agreement Process is particularly suited to transmission facilities that promote state policies, noting that Long-Term Regional Transmission Planning should address state laws and utility integrated resource plans that affect the resource mix, but the cost of the transmission facilities needed to address those issues must be borne by the states and utilities whose laws and integrated resource plans require those facilities.[2926] Likewise, Ohio Commission Federal Advocate asserts that a State Agreement Process is a just and reasonable way of allocating costs for public policy projects.[2927] Relatedly, ELCON states that the Commission should emphasize that one state's public policy goals cannot supplant the cost causation principle or be used to impose costs on customers in states that do not have the same goals.[2928]

1373. Southern also notes that state support for transmission projects is crucial as the states retain primary jurisdiction over transmission siting and certification.[2929] Southern

[2925] Mississippi Commission Initial Comments at 22.

[2926] Mississippi Commission Reply Comments at 3, 24 (citing Alabama Commission Initial Comments at 4; Illinois Commission at 4, 7-8).

[2927] Ohio Commission Federal Advocate Initial Comments at 12.

[2928] ELCON Initial Comments at 17-18. Under the cost causation principle, the cost of transmission facilities must be allocated to those who benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 53 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 586); *see also ICC v. FERC I*, 576 F.3d at 476.

[2929] Southern Initial Comments at 9.

asserts that states should generally be allowed to make transmission project selection and cost allocation decisions pursuant to the State Agreement Process after the planning is performed and specific costs and benefits are identified.[2930] North Carolina Commission and Staff agree that the Commission should allow states to negotiate a cost allocation method after a transmission facility has been selected through Long-Term Regional Transmission Planning.[2931] Similarly, Pennsylvania Commission states that having the State Agreement Process occur after project selection will put planning in the driver's seat, and state negotiation will be centered around a transmission project already selected, which will ensure that project planning and selection run smoothly while not frustrating the fulfillment of a state's need during the state negotiation process.[2932]

1374. Massachusetts Attorney General states that, due to the range and complexity of benefits and the uncertainty associated with using a long transmission planning horizon, permitting states to diverge from *ex ante* cost allocation requirements for particular transmission projects or portfolios of projects may increase the likelihood that those facilities are sited and developed with fewer costly delays and will better ensure just and reasonable rates. Massachusetts Attorney General states that the potential benefits of the State Agreement Process outweigh any concerns about free ridership.[2933] R Street agrees

[2930] *Id.* at 27.

[2931] North Carolina Commission and Staff Initial Comments at 15-16.

[2932] Pennsylvania Commission Initial Comments at 12-13.

[2933] Massachusetts Attorney General Initial Comments at 19 (citing NOPR, 179

that the proposal for a State Agreement Process could reduce cost allocation and siting disputes, but asserts that states lack the jurisdiction and resources to serve an economic oversight role and thus that state participation is not a substitute for the Commission's economic oversight or for competitive mechanisms.[2934]

1375. NESCOE supports the proposal that the State Agreement Process may apply to all, or a subset of, Long-Term Regional Transmission Facilities. NESCOE contends that, depending on the circumstances, Relevant State Entities may find it unnecessary to have the State Agreement Process apply to all such facilities, and having the flexibility to apply the State Agreement Process to a subset of facilities is a reasonable approach.[2935]

### ii. Concerns and Conditions for Support Regarding State Agreement Process

1376. Some commenters qualified their support for the State Agreement Process and/or suggest that the Commission impose conditions upon the process, including those that advocated for flexibility and deference to existing efforts to incorporate state involvement.[2936] US DOE, on behalf of its federal power marketing administrations, notes that, to the extent that state agreements may involve the participation of federal power marketing administrations, the process will need to accommodate the jurisdictional

FERC ¶ 61,028 at PP 299, 314).

[2934] R Street Initial Comments at 4, 12.

[2935] NESCOE Initial Comments at 62-63 (citing NOPR, 179 FERC ¶ 61,028 at P 311).

[2936] *Supra* note 2923.

implications of the parties involved and that any agreements federal power marketing administrations execute must be consistent with their statutory authorities.[2937]

1377. Entergy states its understanding that state agreements will not bind retail commissions in exercising other authorities like siting and permitting.[2938] Likewise, Pennsylvania Commission states that any State Agreement Process cannot serve to waive or diminish the state's siting authority over transmission facilities.[2939]

1378. Mississippi Commission states that involving state regulators in cost allocation ensures that one state's policy choices are not imposed on another state's consumers without their consent and that no state should be forced to subsidize implementation of another state's laws and policies.[2940] Likewise, Avangrid states that one state should not be required to fund public policies of another state, as this could derail clean energy efforts and allow states to avoid paying their fair share.[2941] NRG supports a role for states on transmission projects that would not exist but for state public policy.[2942] Virginia

[2937] US DOE Initial Comments at 50.

[2938] Entergy Initial Comments at 29-30 (citing NOPR, 179 FERC ¶ 61,028 at PP 302-309, 314).

[2939] Pennsylvania Commission Initial Comments at 14.

[2940] Mississippi Commission Reply Comments at 2-3.

[2941] Avangrid Initial Comments at 29.

[2942] NRG Initial Comments at 6.

Commission Staff avers that state entities should retain the right to assume cost responsibility for transmission projects intended to advance their public policy goals.[2943]

1379. Pennsylvania Commission argues that the terms *ex ante* and *ex post* used in the definitions of the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are vague and that instead, the Commission should include in the definitions that the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are determined either before or after a transmission facility is selected.[2944]

1380. Entergy asserts that the Commission should permit flexibility as to when a State Agreement Process occurs despite the NOPR's reference to the State Agreement Process as "an *ex post* cost allocation process" because in some transmission planning regions, it may be appropriate for the State Agreement Process to begin before transmission projects are selected.[2945] Entergy states that any State Agreement Process should be finalized before a portfolio is submitted to the MISO Board of Directors because it will provide certainty to stakeholders as to how costs will be allocated and ensure that the MISO Board of Directors understands how the cost allocation for the portfolio is consistent with the law and capable of withstanding legal challenges.[2946] Relatedly, Mississippi

[2943] Virginia Commission Staff Initial Comments at 6.

[2944] Pennsylvania Commission Initial Comments at 14-15.

[2945] Entergy Initial Comments at 34-35.

[2946] *Id.* at 35.

Commission argues that Long-Term Regional Transmission Facilities should not be presented to an RTO/ISO governing board until states have reached agreement on cost allocation.[2947]

1381. Similarly, MISO asserts that the *ex post* nature of the State Agreement Process renders it unsuitable as the sole cost allocation method for Long-Term Regional Transmission Facilities. As such, MISO contends, cost allocation should be available only during a defined time set forth in the OATT, after the approval of the transmission projects, to avoid delays in the competitive transmission development process. MISO further states that failure to conclude the State Agreement Process in that timeframe should result in the transmission provider reverting to its default Long-Term Regional Transmission Cost Allocation Method. Finally, MISO asks that the Commission clarify that transmission providers can make changes to their competitive transmission development process to accommodate the State Agreement Process.[2948]

1382. DC and MD Offices of People's Counsel recommend that the State Agreement Process afford an opportunity for state entities to participate in transmission project evaluation and selection. They recommend this approach because of regional grid expansions that optimize the interconnection of portfolios of resources that likely result from power supply commitments made in conformity with state policies, and because state entity participation in cost allocation after a transmission project has already been

[2947] Mississippi Commission Initial Comments at 25-26.

[2948] MISO Initial Comments at 69.

selected may foreclose the consideration of state-specific benefits of grid decarbonization during project evaluation and selection.[2949]

1383. Alabama Commission contends that the Commission should provide for flexibility in the form and substance of any state agreement. Specifically, Alabama Commission explains that under Alabama law, it is unclear how the Alabama Commission would enter into such agreement and that its agreement may instead have to take the form of an order directed to Alabama Power.[2950] SERTP Sponsors also state that the Commission should recognize the importance of flexibility in the development and structure of state agreements, agreeing that a state public service commission may not have authority to enter into binding state agreements. SERTP Sponsors offer that a state agreement for a state public service commission could be an endorsement of a voluntary participant funding agreement among its jurisdictional transmission providers.[2951] Southeast PIOs state that the applicable cost allocation method should account for regional preferences and adds that an *ex ante* method is likely a non-starter in the Southeast, but that a State Agreement Process has real potential.[2952]

[2949] DC and MD Offices of People's Counsel Initial Comments at 37-38.

[2950] Alabama Commission Initial Comments at 10 n.8.

[2951] SERTP Sponsors Initial Comments at 28-29.

[2952] Southeast PIOs Reply Comments at 22-23 (citing Dominion Initial Comments at 50-52; Duke Initial Comments at 35-37; SERTP Sponsors Initial Comments at 28-29; Southern Initial Comments at 27-28).

1384. Acadia Center and CLF state that voluntary state agreements relating to offshore wind could result in more efficient and cost-effective Long-Term Regional Transmission Facilities but request further clarity on voluntary agreements to assist states in understanding how these agreements allocate costs of transmission upgrades necessary for increased interconnection of renewable projects.[2953] New England Systems states that the Commission should clarify that any State Agreement Process cannot increase the costs paid by a non-consenting transmission customer under an existing cost allocation method.[2954] Pennsylvania Commission seeks clarification that a state that is not a party to a cost allocation agreement developed through the State Agreement Process cannot be required to pay for a selected transmission project.[2955]

1385. Cypress Creek states that the involvement of states in Long-Term Regional Transmission Planning is important but that a State Agreement Process should not be required.[2956] MISO requests that the State Agreement Process be optional so as not to disrupt current frameworks of state collaboration or delay transmission expansion.[2957] MISO further asserts that the proposed cost allocation reforms may undermine existing

[2953] Acadia Center and CLF Initial Comments at 32 & n.93.

[2954] New England Systems Initial Comments at 23.

[2955] Pennsylvania Commission Initial Comments at 12.

[2956] Cypress Creek Reply Comments at 14 (citing Clean Energy Associations Initial Comments at 34).

[2957] MISO Reply Comments at 19.

cost allocation methods and that the Commission should not extend any requirements regarding state involvement to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final rule.[2958]

1386. In addition, MISO argues that there should be no requirement for unanimous agreement under the State Agreement Process, particularly if the decision to adopt it rests with Relevant State Entities.[2959] MISO states that some flexibility as to what constitutes agreement of Relevant State Entities may be justified.[2960] While Interwest supports increased state engagement, it argues that state entities should not be authorized to limit regional transmission plans by veto or by using unjust and unreasonable cost allocation principles that are subjective or fail to comprehensively consider benefits.[2961]

1387. Chemistry Council contends that consultation with affected states should not give individual states the power to "hijack" the transmission planning process by rejecting necessary investments, withholding consent, or delaying the decision-making process. Chemistry Council asserts that the Commission should clarify that in requiring transmission providers to "seek agreement" from states in transmission project selection,

[2958] MISO Initial Comments at 60, 71.

[2959] *Id.* at 66-67; MISO Reply Comments at 19.

[2960] MISO Initial Comments at 66.

[2961] Interwest Initial Comments at 16.

it is not suggesting that individual states would have a veto in the process or the ability to unduly influence the timing or outcome of decision-making.[2962]

1388. Evergreen Action encourages the Commission to prohibit one state or stakeholder from vetoing transmission projects or cost allocation decisions. Evergreen Action further states that if consensus is not reached under a State Agreement Process, transmission providers should not extend the time allotted to reach agreement, because this would allow individual parties to delay the approval of needed transmission and remove the time pressure on Relevant State Entities to reach agreement. Evergreen Action avers that instead transmission providers should simply explain that they conducted a good-faith effort to reach agreement.[2963]

1389. SEIA also urges the Commission to limit the opportunity for any single state to veto a transmission line and to use its backstop authority under section 216 of the FPA if parties are unable to reach an agreement and a relevant state authority withholds or denies the siting permit for the transmission facility.[2964] US Climate Alliance agrees that the process should encourage states to engage in good faith discussions to realize common benefits without over-leveraging a single state's power over a regional transmission project.[2965] National Grid suggests that if states cannot agree within a reasonable period

[2962] Chemistry Council Initial Comments at 7.

[2963] Evergreen Action Initial Comments at 6.

[2964] SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

[2965] US Climate Alliance Initial Comments at 2.

on a proposed cost allocation method for a specific set of Long-Term Regional Transmission Facilities, then the transmission providers or developers building those facilities should be required to file a proposed cost allocation method for them.[2966] In contrast, NRG states that without recourse to an *ex ante* cost allocation method, negotiations under the State Agreement Process would be more productive.[2967]

1390. California Commission is concerned that the NOPR proposal grants too much deference to transmission providers and will enable them to exercise veto power over state-negotiated cost allocation agreements.[2968] California Municipal Utilities and TANC ask that the Commission require that local regulatory authorities be included in any State Agreement Process, stating that the jurisdictional implications of the NOPR proposal are unclear given that public power entities are not generally subject to the jurisdiction of their respective state commissions.[2969] Mississippi Commission and Northwest and Intermountain support expanding a State Agreement Process to include non-jurisdictional utilities.[2970] California Municipal Utilities further assert that, if any state body is created

[2966] National Grid Initial Comments at 25-26.

[2967] NRG Initial Comments at 20-21.

[2968] California Commission Initial Comments at 51, 54-55 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

[2969] California Municipal Utilities Initial Comments at 16; TANC Initial Comments at 17.

[2970] Mississippi Commission Reply Comments at 5 (citing MISO Coops Initial Comments at 3-4); Northwest and Intermountain Initial Comments at 18.

to examine transmission planning issues, it must include public power entities.[2971] Because the written comment process is not sufficient to facilitate a constructive dialogue, California Municipal Utilities urge the Commission to refrain from adopting any specific proposals from the NOPR until such a dialogue between states and public power can occur.[2972]

1391. Some commenters are concerned about the reliance on voluntary contributions that may occur under a State Agreement Process. Clean Energy Associations states that while *ex post* frameworks that rely on voluntary contributions from states or interconnection customers may be useful in some circumstances, they may not appropriately acknowledge system-wide benefits of high-voltage elements, which under the State Agreement Process could be treated as benefitting only a single state. According to Clean Energy Associations, courts have found such an outcome improper, and this approach is unlikely to yield agreement in practice.[2973] Likewise, Cypress Creek asserts that any *ex post* cost allocation method should acknowledge wide-spread benefits without imposing new restrictions.[2974] AEE contends that the State Agreement Process, and more broadly the requirement to seek agreement of states regarding applicable cost

[2971] California Municipal Utilities Initial Comments at 4.

[2972] California Municipal Utilities Reply Comments at 10.

[2973] Clean Energy Associations Initial Comments at 35 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1261).

[2974] Cypress Creek Reply Comments at 14.

allocation methods, should not substitute for allocating costs to all beneficiaries based on the broad set of benefits that regional transmission investment can provide. AEE states that reliance on voluntary state agreement should allow all states to consider the broad benefits that additional regional transmission facilities provide and the legal obligation to allocate costs commensurate with benefits received.[2975]

1392. DC and MD Offices of People's Counsel suggest that cost allocation should be based on the NOPR's defined benefits to all appropriate beneficiaries, with a further cost allocation to states that opt to submit additional transmission needs. DC and MD Offices of People's Counsel state that this approach would be more expansive than the existing State Agreement Approach in PJM because it would allow for a parallel default allocation of costs to the state entities not opting in, but narrowed to align with the NOPR-listed benefits, and a second round of cost allocation after the participating Relevant State Entities have shared costs aligned with the broader measure of benefits, which would help avoid the free-rider problem.[2976]

1393. Avangrid states that a fair approach to cost allocation under the State Agreement Process could be payments and benefits based on tiers, providing the example that if states A and B have public policies supported by new transmission while state C does not, then only states A and B should pay the cost of public policy benefits while all three

[2975] AEE Reply Comments at 15-16.

[2976] DC and MD Offices of People's Counsel Initial Comments at 38-39 (citing *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024).

states should be responsible for the cost associated with economic and reliability benefits.[2977] Similarly, PIOs assert that under the State Agreement Process, costs identified in Long-Term Regional Transmission Planning should first be allocated to transmission customers as the primary beneficiaries, and then states and/or interconnection customers can voluntarily accept cost allocation for the alternative or expanded transmission projects compared to projects identified in the regional base case plan.[2978]

1394. AEE asks that the Commission provide additional guardrails for the State Agreement Process to ensure that there are not transmission project delays.[2979] According to AEE, the Commission must ensure that excessive reliance on the State Agreement Process does not exacerbate free-ridership problems where states outside of those agreements receive benefits from transmission projects developed under state agreements but are not expected to contribute to the costs.[2980]

1395. Duke argues that any tariff language memorializing the State Agreement Process must specify that the transmission provider "will not be obligated to accept cost

[2977] Avangrid Initial Comments at 29-30.

[2978] PIOs Initial Comments at 68 (citing NOPR, 179 FERC ¶ 61,028 at PP 75-76).

[2979] AEE Initial Comments at 33 (citing NOPR, 179 FERC ¶ 61,028 at PP 311-318).

[2980] *Id.*

allocation methods proposed by Relevant State Entities."[2981] Duke also asks that the Commission clarify that if transmission providers only adopt a State Agreement Process, and that fails, then transmission providers are free to make an FPA section 205 filing to implement an *ex post* cost allocation method.[2982] Further, Duke asks that the Commission clarify that the regulatory text's reference to "transmission provider" is "the entity with the section 205 rights to initiate rate changes, which depending upon the applicable governance and OATT structures, may be the transmission owner, but not the transmission provider."[2983]

1396. Some commenters support requiring state involvement in cost allocation. For example, New York Commission and NYSERDA state that state-led cost allocation should be a requirement in any final rule and that cost allocation for public policy-driven transmission projects should be subject to state review and approval.[2984] Pacific Northwest State Agencies support requiring transmission providers to have an *ex post* State Agreement Process as an alternative to an *ex ante* cost allocation method.[2985]

[2981] Duke Initial Comments at 39-40.

[2982] *Id.* at 3.

[2983] *Id.* at 40 n.77.

[2984] New York Commission and NYSERDA Initial Comments at 12, 14.

[2985] Pacific Northwest State Agencies Initial Comments at 27.

### iii. Opposition to a State Agreement Process

1397. Some commenters express concern that a State Agreement Process may not be a just and reasonable approach to cost allocation for regional transmission facilities.[2986] R Street contends that states do not represent all beneficiaries who may be assigned costs and, as such, cost allocation predicated on state agreement may be unjust and unreasonable. R Street states, however, that a state advisory or partial approval mechanism could be structured to give state agreement pivotal influence over cost allocation decisions.[2987]

1398. APPA claims that the proposed State Agreement Process is unworkable and creates significant uncertainty and potential for litigation.[2988] APPA further asserts that providing state regulators with an exclusive role in determining cost allocation methods will not likely result in a broad consensus across stakeholders.[2989] MISO Coops add that it is unjust and unreasonable, arguing that, because cooperatives are often not jurisdictional to a state entity, it is unclear how cooperatives would be represented. Thus, MISO Coops state, the State Agreement Process would reduce the involvement of cooperatives in regional transmission planning processes while granting states authority

[2986] APPA Initial Comments at 40, 44; MISO Coops Initial Comments at 2; R Street Initial Comments at 12.

[2987] R Street Initial Comments at 12.

[2988] APPA Initial Comments at 40, 44.

[2989] *Id.* at 43.

over entities outside their jurisdiction. MISO Coops further state that the proposed State Agreement Process is unnecessary because the current MISO stakeholder process is superior.[2990] MISO TOs oppose any provision that would mandate a State Agreement Process.[2991]

#### iv. Requirement to Document State Agreement Process in OATT

1399. Some commenters agree with the NOPR proposal that for any State Agreement Process, transmission providers in each transmission planning region must detail in their OATTs the process by which Relevant State Entities would reach agreement regarding the cost allocation for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, including the timeline for such processes.[2992] NESCOE contends that if the State Agreement Process is chosen by the Relevant State Entities, the details of how the state entities would agree to funding contributions and the mechanisms by which the costs would be allocated should be mostly informed by states and then filed by the transmission provider.[2993] NESCOE suggests that the Commission be open to variations

[2990] MISO Coops Initial Comments at 2-4.

[2991] MISO TOs Initial Comments at 5, 46.

[2992] Louisiana Commission Initial Comments at 33; NESCOE Initial Comments at 63; SDG&E Initial Comments at 5; TAPS Initial Comments at 24.

[2993] NESCOE Initial Comments at 63.

in the State Agreement Process as long as the details of all those variations are filed with the Commission.[2994]

1400. Northwest and Intermountain state that the Commission should review negotiated cost allocation methods.[2995] Likewise, APPA argues that the Commission should require that any state agreement to voluntarily fund transmission facilities must be filed with the Commission for approval, in order to afford parties the opportunity to comment.[2996]

1401. Some commenters disagree that the Commission should require transmission providers in each transmission planning region to detail such processes in their OATTs. For example, OMS argues that it is unnecessary for transmission providers to explicitly define such a process in their OATTs.[2997] Mississippi Commission argues that the Commission should clarify that OATT language describing the process by which states reach agreement should not be prescriptive or limiting and, instead, should provide only a general discussion of a process.[2998]

### c. Commission Determination

1402. We adopt the NOPR proposal, with modification, to allow, but not require, transmission providers in each transmission planning region to adopt a State Agreement

[2994] NESCOE Reply Comments at 5.

[2995] Northwest and Intermountain Initial Comments at 18-19.

[2996] APPA Initial Comments at 34-35.

[2997] OMS Initial Comments at 12-13.

[2998] Mississippi Commission Initial Comments at 27-28.

Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities. We also modify the definition of State Agreement Process to be a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. We note that Relevant State Entities have the option to include the participation of other entities in a State Agreement Process.

1403. As discussed in more detail below, we also adopt the NOPR proposal to require transmission providers that choose to file any State Agreement Process agreed to by Relevant State Entities to describe the State Agreement Process in proposed tariff provisions in their OATTs. The tariff provisions must describe key information on how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the transmission providers; and the circumstances under which, or the information necessary for, transmission providers to file or to consider filing the agreed cost allocation method.[2999]

1404. Consistent with the NOPR, we find that a State Agreement Process can be a just and reasonable approach to allocate costs for Long-Term Regional Transmission Facilities. We also find that State Agreement Processes may apply to all Long-Term

[2999] NOPR, 179 FERC ¶ 61,028 at P 313.

Regional Transmission Facilities or only to a subset thereof.[3000] We believe that allowing State Agreement Processes will help to address some commenters' request for a stronger state role in the cost allocation of Long-Term Regional Transmission Facilities,[3001] increasing the likelihood that more efficient or cost-effective Long-Term Regional Transmission Facilities that are selected will be developed. However, as discussed in Cost Allocation Methods for Long-Term Regional Transmission Facilities section above, a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities; we also require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final rule so that if the State Agreement Process on file fails to result in a Commission-accepted cost allocation method, there will still be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1405. We note that this final rule provides significant flexibility to Relevant State Entities with respect to the design and implementation of any State Agreement Process. Such flexibility includes, for example, the opportunity to decide which entities beyond Relevant State Entities will participate in the State Agreement Process, the ability to

[3000] *Id.* P 311.

[3001] *See, e.g.*, Mississippi Commission Initial Comments at 22; Southern Initial Comments at 9.

identify the Long-Term Regional Transmission Facilities to which the State Agreement Process will apply, and how agreement as to a cost allocation method will be reached.

1406. We further expand these flexibilities by modifying the NOPR proposal to clarify that a State Agreement Process can occur either before or no later than six months after a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected. We believe that providing flexibility for a State Agreement Process to occur (and thus for the Relevant State Entities to agree on a cost allocation method) before Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) are selected will increase the likelihood that Regional State Entities support their selection and future development. We note that this flexibility with regard to the timing of a State Agreement Process should accommodate the timing preferences expressed by certain commenters.[3002] However, we also require that any State Agreement Process must be completed, i.e., any resulting cost allocation method must be filed with the Commission, no later than six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities).[3003]

1407. As the Commission has previously noted, agreements outside of the context of Order No. 1000 regional cost allocation methods, such as PJM's State Agreement Approach, can result in cost allocations that are just and reasonable.[3004] We also note that

[3002] *See, e.g.*, Pennsylvania Commission Initial Comments at 12-13; Entergy Initial Comments at 35.

[3003] We discuss this duration requirement *infra* at P 1413.

[3004] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 142; *PJM*

Order No. 1000 allows market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or set of methods, and nothing in this final rule would prohibit such voluntary cost sharing arrangements.[3005] Moreover, as the Commission noted in the NOPR, the Commission recently issued a Policy Statement addressing state efforts to develop transmission facilities through voluntary agreements to plan and pay for those facilities, recognizing that such voluntary agreements may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are through the regional transmission planning process.[3006] Further, while we require in this final rule that transmission providers have a Long-Term Regional Transmission Cost Allocation Method for selected Long-Term Regional Transmission Facilities, we note that nothing in this final rule limits a transmission provider's ability to propose under FPA section 205 any other cost allocation methods in addition to the cost allocation method used to comply with this final rule.

1408. In the NOPR, the Commission noted that it has previously expressed concern regarding participant funding, which shares some similarities with State Agreement

*Interconnection, L.L.C.*, 179 FERC ¶ 61,024 at PP 40-43.

[3005] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 561.

[3006] NOPR, 179 FERC ¶ 61,028 at P 300 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at PP 2, 6).

Processes.[3007] In Order No. 1000, for example, the Commission explained that reliance on participant funding as a regional cost allocation method "increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development" and would therefore not comply with the Order No. 1000 regional cost allocation principles.[3008] The Commission declined to allow transmission providers to file participant funding cost allocation approaches as their *ex ante* cost allocation methods for selected regional transmission facilities.[3009] We take a similar approach here: we require transmission providers to include in their OATTs one or more Long-Term Regional Transmission Cost Allocation Methods (i.e., their *ex ante* cost allocation method(s)) that can be used to allocate the costs of selected Long-Term Regional Transmission Facilities. As in Order No. 1000, the Long-Term Regional Transmission Cost Allocation Method cannot be participant funding. We find that requiring a Long-Term Regional Transmission Cost Allocation Method or Methods that will apply to any selected Long-Term Regional Transmission Facility reduces the incentive for project beneficiaries to defer investment.

[3007] *See id.* P 316 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 723).

[3008] *Id.* P 316 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 723). Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. *Id.* P 316 n.519 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486 n.375).

[3009] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 723.

1409. However, in addition to requiring a Long-Term Regional Transmission Cost Allocation Method, we also provide flexibility to Relevant State Entities to agree to a State Agreement Process, which transmission providers may choose to file as part of their compliance filings. We conclude that allowing such an approach as an option is reasonable despite the Commission's previously-stated concerns with participant funding, because a State Agreement Process is an established process, agreed to in advance and described in transmission providers' OATTs, through which Relevant State Entities agree to a cost allocation method. We find that, for the purposes of Long-Term Regional Transmission Planning, a State Agreement Process will help to facilitate agreement and cooperation among Relevant State Entities. We find that this approach balances the need for the certainty with respect to cost allocation provided by an *ex ante* cost allocation method with the flexibility of allowing for a State Agreement Process-derived cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities). We emphasize, however, that the Commission will still review any cost allocation method that results from a State Agreement Process to ensure that it is just and reasonable and not unduly discriminatory or preferential, and that it allocates costs in a manner that is at least roughly commensurate with estimated benefits.

1410. In the context of Long-Term Regional Transmission Planning, we believe that allowing the use of State Agreement Processes to derive a cost allocation method for selected Long-Term Regional Transmission Facilities will provide states with an opportunity to be more involved in cost allocation for these transmission facilities, leading to an increased likelihood that such facilities are developed. Specifically, the

engagement of Relevant State Entities in cost allocation discussions could reduce instances in which a Long-Term Regional Transmission Facility is selected and has an established *ex ante* cost allocation method that applies to it, but ultimately is not developed because it does not receive a necessary state approval.[3010] We also find that a State Agreement Process could provide greater confidence to Relevant State Entities that customers are receiving benefits in a manner that is at least roughly commensurate with the costs they are paying for Long-Term Regional Transmission Facilities.

1411. We acknowledge commenters' concerns that a State Agreement Process could present free-ridership issues.[3011] For example, there could be free-ridership concerns if the Relevant State Entities in certain states agree to be allocated all of the costs for a particular Long-Term Regional Transmission Facility but that facility also benefits other entities in other states that are not similarly allocated costs under the cost allocation method arrived at through the State Agreement Process. However, we continue to find that allowing a State Agreement Process for Long-Term Regional Transmission Facilities, where agreed to by the Relevant State Entities, appropriately balances free-ridership concerns with the benefit of greater state involvement in determining the cost allocation method for Long-Term Regional Transmission Facilities and the increased likelihood that such facilities will be built.[3012] Additionally, nothing in this final rule

[3010] NOPR, 179 FERC ¶ 61,028 at P 314.

[3011] *See, e.g.*, R Street Initial Comments at 12.

[3012] NOPR, 179 FERC ¶ 61,028 at P 317.

changes the requirements for all cost allocation methods, including those that result from a State Agreement Process, to allocate costs in a manner that is at least roughly commensurate with estimated benefits, and we believe that Commission review to ensure that cost allocation methods meet that standard will act to prevent free ridership.

1412. As noted above, there is significant commenter support for a State Agreement Process, particularly among state entities. In addition, we believe that many of the concerns expressed about the State Agreement Process proposal appear to be based on a lack of sufficient explanation in the NOPR regarding the implications of the proposal, which we clarify here. Contrary to some comments, we do not require transmission providers to adopt a State Agreement Process; rather, as discussed in the Filing Rights Under the FPA section, transmission providers may choose to file a State Agreement Process for all, or a subset of, Long-Term Regional Transmission Facilities on compliance. Also, we neither impose an obligation on a state or states to agree to a cost allocation method for Long-Term Regional Transmission Facilities, nor do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs.[3013] As we note in the discussion of transmission provider filing rights in the Filing Rights Under the FPA section below, we believe that the applicable statute

[3013] For example, transmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.

and precedent require us to preserve the right of transmission providers to file with the Commission their preferred cost allocation method for Long-Term Regional Transmission Facilities to comply with the requirements of this final rule.

1413. However, as noted earlier in this section, we establish a deadline of no later than six months after selection of a Long-Term Regional Transmission Facility (or portfolio of such Facilities) by which transmission providers must file any cost allocation method that results from a State Agreement Process. We believe that the State Agreement Process can only be effective if there is a limit on the time to reach agreement before defaulting to the Long-Term Regional Transmission Cost Allocation Method that we require transmission providers include in their OATTs. The lack of such a deadline could cause delay and increase uncertainty regarding selected Long-Term Regional Transmission Facilities. In addition, we agree with some commenters[3014] that a deadline, bolstered by a default Long-Term Regional Transmission Cost Allocation Method, may increase the incentive for Relevant State Entities to reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.

1414. We find that six months is a reasonable period for State Agreement Process deliberations on a cost allocation method because it balances the need for adequate time for negotiations with transmission providers' need for finality in their Long-Term Regional Transmission Planning. While few commenters directly addressed the time

[3014] *See* Evergreen Action Initial Comments at 6; MISO Initial Comments at 67-68; National Grid Initial Comments at 25-26.

period for negotiation under a State Agreement Process for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), many commenters favored this duration for the NOPR proposed reform of a post-selection time period for states to negotiate an alternate cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities) when an *ex ante* cost allocation method would otherwise apply.[3015]

1415. We clarify that, if the Relevant State Entities indicate to transmission providers, as part of the required Engagement Period outlined above, that the Relevant State Entities have agreed to a State Agreement Process, and the transmission providers decide to include that State Agreement Process in their final rule compliance filings, then the transmission providers must also detail the State Agreement Process in proposed tariff provisions to their OATTs. The tariff provisions must describe how agreement would be reached regarding the cost allocation method for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, which also necessarily requires that it be clear which entities can participate in the specific State Agreement Process.[3016] This requirement is in furtherance of one of the goals of the final rule, which is to allow a

[3015] California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial Comments at 34-35; NARUC Initial Comments at 52-53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27-28.

[3016] NOPR, 179 FERC ¶ 61,028 at P 313.

greater role for states in establishing a cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities).

1416. As noted above, after the required initial Engagement Period, a State Agreement Process could include other entities beyond Relevant State Entities, and those entities would need to be enumerated in the State Agreement Process included in the OATT. Transmission providers must first specify in their OATTs a description of how such voluntary agreements by the Relevant State Entities may be shared with transmission providers, as well as whether the transmission providers voluntarily agree to undertake an obligation to file the agreed-upon cost allocation method with the Commission for consideration under FPA section 205 (in other words, whether the transmission providers voluntarily waive their FPA section 205 filing rights such that they commit themselves to file with the Commission any cost allocation method that results from the State Agreement Process). Their OATT provisions must, at a minimum, also include the event triggering the beginning of the State Agreement Process, the duration of the State Agreement Process (not to exceed six months after selection), and a description of the Long-Term Regional Transmission Facilities to which the process applies. Further, the State Agreement Process procedures outlined in transmission providers' OATTs must set forth the manner in which a transmission provider would file a section 205 filing to seek Commission acceptance of a cost allocation method resulting from a State Agreement Process. We note that Relevant State Entities that participate in a State Agreement Process may need to provide relevant information to transmission providers to enable them to demonstrate that any cost allocation method that results from a State Agreement

Process is just, reasonable, and not unduly discriminatory or preferential, and allocates cost in a manner that is at least roughly commensurate with estimated benefits.

1417. We do not agree with the commenters that recommend against memorializing and filing cost allocation methods resulting from a State Agreement Process with the Commission.[3017] To fulfill the Commission's statutory obligations, any cost allocation method that results from a State Agreement Process must be filed for review by the Commission and determined to be just, reasonable, and not unduly discriminatory or preferential. In addition, we believe that transparency regarding such cost allocation methods and the opportunity for stakeholders, particularly those that will be responsible for paying the costs of Long-Term Regional Transmission Facilities, to comment on them are an important safeguard to ensure that costs are allocated in a manner that is at least roughly commensurate with estimated benefits.

1418. We will not specify the level of agreement among Relevant State Entities or other entities that is necessary before a transmission provider files a cost allocation method derived from a State Agreement Process. As a state-led process, we believe that Relevant State Entities should have the ability to determine this important facet of their State Agreement Process. To this end, we decline to require unanimity or a set minimum threshold for agreement of Relevant State Entities to participate in the State Agreement Process.

[3017] Mississippi Commission Initial Comments at 27-28; OMS Initial Comments at 12-13.

1419. Some commenters request that the Commission clarify whether and to what extent a cost allocation method that results from a State Agreement Process can impose costs on entities that do not agree to that cost allocation method. However, we decline to prejudge any State Agreement Process or any cost allocation method that may result from a State Agreement Process. Any cost allocation method for a Long-Term Regional Transmission Facility (or portfolio of such Facilities) that results from a State Agreement Process must be filed with the Commission pursuant to FPA section 205, and the Commission must make a finding as to whether that cost allocation method is just, reasonable, and not unduly discriminatory or preferential. And, as noted above, we reiterate that all cost allocation methods, including those resulting from a State Agreement Process, must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[3018] Parties are free to raise any concerns about the costs that they may be allocated under a State Agreement Process-derived cost allocation method if and when that method is filed with the Commission.[3019]

1420. MISO asks that the final rule make clear that transmission providers can make necessary changes to the competitive transmission developer selection process to accommodate the State Agreement Process.[3020] We clarify that the Commission will

[3018] *See ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564.

[3019] *E.g.*, New England Systems Initial Comments at 23; Pennsylvania Commission Initial Comments at 12; Mississippi Commission Reply Comments at 3.

[3020] MISO Initial Comments at 68-70.

review any proposed changes to transmission providers' competitive transmission developer selection processes to accommodate State Agreement Processes as part of their compliance filings to this final rule.

1421. With respect to California Municipal Utilities' and TANC's requests that the Commission require that local regulatory authorities be included in any State Agreement Process, the Mississippi Commission's statement that it would support expanding the State Agreement Approach to include non-jurisdictional utilities, we do not proscribe in this final rule that the State Agreement Processes include other entities beyond Relevant State Entities. However, as noted above, Relevant State Entities have the option to include the participation of other entities in a State Agreement Process. Finally, with respect to US DOE's comments related to the jurisdictional implications of federal power marketing administrations participating in State Agreement Processes, we do not establish any specific requirements for how State Agreement Processes will be designed. To the extent that a federal power marketing administration does participate in such a process, it may advocate that such process facilitates its participation in a manner that is consistent with its statutory authority.[3021]

### 4. Filing Rights Under the FPA

#### a. Comments

1422. A number of commenters express concerns that a requirement to seek agreement from Relevant State Entities regarding a cost allocation approach could conflict with

[3021] US DOE Initial Comments at 50.

transmission providers' filing rights under the FPA.[3022] For example, AEP contends that in at least one region where AEP operates, such a requirement would deprive transmission owners of their exclusive right to file tariffs governing the rates and terms of their transmission service under section 205 of the FPA. AEP states that in *Atlantic City Electric Company v. FERC*, the D.C. Circuit, held that "[w]hen FERC attempts to deprive the utilities of their rights to initiate rate design changes with respect to services provided by their own assets, FERC has exceeded its jurisdiction."[3023]

1423. Similarly, Dominion reminds the Commission that the transmission provider has FPA section 205 rights, and that those rights cannot be ceded to the state through this proceeding.[3024] National Grid asserts that the FPA gives transmission providers the ability to make section 205 filings on cost allocation, and that the State Agreement

[3022] AEP Initial Comments at 6, 36 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9-11 ("[T]his Court, among others, has stressed that the power to initiate rate changes rests with the utility and cannot be appropriated by FERC in the absence of a finding that the existing rate was unlawful."); *Atl. City Elec. Co. v. FERC*, 329 F.3d 856, 858-59 (D.C. Cir. 2003) (per curiam)); MISO Initial Comments at 63-64 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9-11); MISO TOs Initial Comments at 37, 39-40 (citing 16 U.S.C. 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9-11; *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042, at P 107 (2010); *Mass. Dep't of Pub. Utils. v. FERC*, 729 F.2d 886, 887-88 (1st Cir. 1984)); PPL Initial Comments at 25 & n.66 ("[T]he *Atlantic City* case makes clear that the transmission owners are able to make Section 205 filings regarding cost allocation without additional conditions and the Commission cannot compel the transmission owners to cede these rights.").

[3023] AEP Initial Comments at 36 (quoting *Atl. City Elec. Co. v. FERC*, 329 F.3d at 859); *accord* MISO Initial Comments at 63; MISO TOs Initial Comments at 40; PPL Initial Comments at 25 n.66.

[3024] Dominion Initial Comments at 48-49 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1; *Atl. City Elec. Co. v. FERC*, 329 F.3d 856).

Process should be based on transmission providers voluntarily affording a role for states.[3025]

1424. APPA contends that requiring public utilities to file rate terms dictated by non-public utility entities raises jurisdictional issues under the FPA. APPA does not believe it is reasonable to provide to state regulators exclusive authority over the proposed cost allocation method in the absence of agreement by relevant stakeholders, and argues that if the Commission requires public utilities to file cost allocation methods agreed to by Relevant State Entities, public power utilities should be considered Relevant State Entities have a formal voting role in agreeing on the cost allocation method(s) for Long-Term Regional Transmission Facilities.[3026] Six Cities and Large Public Power argue that the Commission's proposal is an unlawful delegation of the Commission's exclusive statutory authority over rates under the FPA.[3027]

1425. Some commenters seek clarification on the Commission's proposal. MISO and Vistra request that the Commission clarify that nothing in the final rule should be read to override or diminish the filing rights held, jointly and/or individually, by the RTOs/ISOs

[3025] National Grid Initial Comments at 25.

[3026] APPA Initial Comments at 42-45.

[3027] Large Public Power Initial Comments at 37-38 (citing *City of Tacoma v. FERC*, 331 F.3d 106, 115 (D.C. Cir. 2002) (finding that the Commission unlawfully delegated its responsibility to assess annual charges imposed under the FPA against hydroelectric utilities licenses to other federal agencies) (additional citations omitted)); Six Cities Initial Comments at 8-9 (citing 16 U.S.C. 824d(a), 824e; *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 965-66 (1986); *EPSA*, 577 U.S. at 277).

and their transmission owning members.[3028] Indicated PJM TOs argue that, while *seeking* the agreement of Relevant State Entities is appropriate, the Commission does not have the authority to require that transmission providers *obtain* their agreement.[3029] Similarly, WIRES states that the Commission should clarify that transmission providers are only required to *seek* agreement of Relevant State Entities and that they are not required to achieve such agreement.[3030] Duke asserts that the Commission should clarify and revise the proposed State Agreement Process to ensure that it does not conflict with transmission providers' FPA section 205 rights to initiate rate changes.[3031]

1426. PJM States propose that if retail regulators reach an agreement on cost allocation, transmission providers should be required to file it for consideration under section 205 of the FPA.[3032] PJM States recommend that if the transmission providers in a transmission planning region prefer a different cost allocation method, they can file their preferred alternative while also presenting the method agreed on by the Relevant State Entities.[3033]

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[3028] MISO Initial Comments at 64; Vistra Initial Comments at 29-30.

[3029] Indicated PJM TOs Initial Comments at 20 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 10-11).

[3030] WIRES Initial Comments at 12 (citing 16 U.S.C. 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9-11; *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858-59).

[3031] Duke Initial Comments at 39 (citing *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858-59).

[3032] PJM States Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 303).

[3033] *Id.* at 10.

PJM States add that these proposals should be "balanced" and explain how the retail regulators' preferences were considered.[3034] Similarly, NESCOE states that in cases of disagreement between state entities and transmission providers, they would prefer that the transmission providers file a state-preferred cost allocation method alongside their own preferred method, arguing that such an approach would respect the FPA section 205 rights that public utilities hold.[3035] Similarly, New Jersey Commission recommends that in the event that the transmission provider disagrees with the approach desired by states, the Commission should require them to submit the states' approach as well as their own in their section 205 filing. New Jersey Commission proposes that the Commission would then decide which OATT filing to accept.[3036]

1427. Entergy contends that the proposal is within the Commission's authority because the Commission's proposal allows transmission providers to retain their filing rights consistent with *Atlantic City*. Entergy argues that the NOPR proposal does not conflict with *Atlantic City* because it would only establish a process where states are consulted on designing a cost allocation method, and that transmission providers still must make a cost allocation filing, even if there is no agreement.[3037]

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[3034] *Id.* at 10.

[3035] NESCOE Reply Comments at 4.

[3036] New Jersey Commission Initial Comments at 17-18.

[3037] Entergy Initial Comments at 31-33 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 11).

**b. Commission Determination**

1428. As a threshold matter, we note that the Commission is acting pursuant to FPA section 206 in this final rule. Under FPA section 206, the Commission has determined that existing regional transmission planning and cost allocation requirements are unjust, unreasonable, unduly discriminatory or preferential, and thus has both the authority and responsibility to establish a just and reasonable replacement rate consistent with the final rule's requirements.[3038]

1429. As to commenters' FPA section 205 arguments, we find that our directives in this final rule regarding the development of a State Agreement Process and any cost allocation methods to which the Relevant State Entities agree pursuant to that process do not alter existing FPA section 205 filing rights.[3039] Specifically, we clarify that, after the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings.[3040] Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method and not file a

[3038] 16 U.S.C. 824e(a) ( "[T]he *Commission* shall determine the just and reasonable . . . practice . . . to be thereafter observed and in force, and shall fix the same by order." (emphasis added)).

[3039] *See* Dominion Initial Comments at 48-49 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1; *Atl. City Elec. Co. v. FERC*, 329 F.3d 856).

[3040] We note that the filing must include a Long-Term Regional Transmission Cost Allocation Method (i.e., an *ex ante* cost allocation method).

State Agreement Process or other *ex ante* cost allocation method to which Relevant State Entities agreed. In addition, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs. In the same vein, we decline to require, as PJM States, NESCOE, and New Jersey Commission suggest, that transmission providers file two cost allocation methods – the transmission providers' preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities – if the transmission providers disagree with a proposed cost allocation method to which the Relevant State Entities agree.[3041] Entities that oppose or prefer a different cost allocation method than the transmission providers' preferred cost allocation method can provide their comments if and when such cost allocation method is filed with the Commission.

1430. We further clarify that unless voluntarily waived, a transmission provider retains its FPA section 205 filing rights to submit an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities at any time,[3042] consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an

[3041] PJM States Initial Comments at 10; NESCOE Reply Comments at 4; New Jersey Commission Initial Comments at 17-18.

[3042] *See Atl. City Elec. Co. v. FERC*, 295 F.3d at 9-11; *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858-859.

RTO/ISO. In response to MISO and Vistra,[3043] we also clarify that nothing in this final rule should be read to override or diminish the filing rights held, jointly or individually, by RTOs/ISOs and their transmission owning members.

1431. In response to commenters arguing that the NOPR proposal to require transmission providers to seek agreement of Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof would interfere with transmission providers' filing rights under FPA section 205,[3044] those concerns are moot, as we decline to adopt this NOPR proposal, as discussed above. We reiterate that transmission providers retain their right to decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file in compliance with this final rule after the Engagement Period.

### 5. Time Period and Related Issues in the Long-Term Regional Transmission Planning Cost Allocation Processes for State-Negotiated Alternate Cost Allocation Method

#### a. NOPR Proposal

1432. In the NOPR, the Commission proposed to require transmission providers to detail in their OATTs a process to provide a state or states (in multi-state transmission planning regions) with a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected through Long-Term Regional Transmission

[3043] MISO Initial Comments at 64; Vistra Initial Comments at 29-30.

[3044] AEP Initial Comments at 36; APPA Initial Comments at 42; Dominion Initial Comments at 48-49; MISO Initial Comments at 63-64; MISO TOs Initial Comments at 37, 39-40; MISO TOs Reply Comments at 5-7; PPL Initial Comments at 25 & n.66.

Planning that is different than any *ex ante* regional cost allocation method (i.e., Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply. During this time period, if a state or all states within the transmission planning region in which the selected regional transmission facility will be located unanimously agree on an alternate cost allocation method, the transmission provider may elect to file that method with the Commission for consideration under FPA section 205. The Commission explained that the transmission provider may elect to file an alternate cost allocation method because doing so increases the likelihood that relevant stakeholders perceive the cost allocation as fair and that the needed regional transmission facilities will actually be constructed.[3045]

1433. If the relevant state or states cannot agree on an alternate cost allocation method memorialized in writing within the specified timeframe after a transmission developer's transmission facility is selected through Long-Term Regional Transmission Planning (e.g., 90 days), the Commission proposed that then the transmission developer would be entitled to use any *ex ante* Long-Term Regional Transmission Cost Allocation Method that would otherwise apply for that Long-Term Regional Transmission Facility.[3046]

1434. In particular, the Commission proposed to require that the OATT provisions that describe the state-negotiated alternate cost allocation method include when this time period will occur, what its duration will be, and an affirmation that any alternate cost

[3045] NOPR, 179 FERC ¶ 61,028 at P 319.

[3046] *Id.* P 320.

allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect. Under this proposal, when filed, the Commission would evaluate the alternate cost allocation method to ensure that it is just and reasonable and allocates costs in a manner that is at least roughly commensurate with estimated benefits. If the Commission rejects a state-negotiated alternate cost allocation method, the transmission developer of the Long-Term Regional Transmission Facility would be entitled to use the applicable *ex ante* regional cost allocation method that would have applied to it in the absence of the proposed alternative cost allocation method.[3047] The Commission proposed to prescribe a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.[3048]

1435. Finally, the Commission sought comment on whether to establish a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes.[3049]

**b. Comments**

1436. Several commenters support the Commission's proposal to require transmission providers to detail in their OATTs a process to provide a state or states with a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities)

[3047] *Id.* P 322.

[3048] *Id.* P 323.

[3049] *Id.* P 324.

selected through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method (i.e., Long-Term Regional Transmission Cost Allocation Method).[3050] NESCOE, Pennsylvania Commission, and PJM States support a requirement for transmission providers to detail in their OATT provisions that describe the state-negotiated cost allocation method.[3051] Clean Energy Buyers, Dominion, and PIOs agree that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect.[3052]

1437. PJM and Nebraska Commission support the proposal to require a time period for state-negotiated alternate cost allocation with suggested modifications. Nebraska Commission states that a process that builds consensus is important for contentious issues such as cost allocation and suggests adoption of a model similar to SPP's Regional State Committee, which it contends has a proven track record for achieving consensus among stakeholders.[3053] PJM recommends that the Commission provide clear direction as to the circumstances under which a process for states to negotiate an alternate cost allocation

[3050] Entergy Initial Comments at 29-30; Nebraska Commission Initial Comments at 9; New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18-19; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27-28; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

[3051] NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12-13.

[3052] Clean Energy Buyers Initial Comments at 29-30; Dominion Initial Comments at 52; PIOs Initial Comments at 71.

[3053] Nebraska Commission Initial Comments at 9.

method would be appropriate. PJM also proposes that states seeking a state-negotiated alternate cost allocation method should be required to explain why the *ex ante* cost allocation method is not appropriate for the identified transmission facility or facilities.[3054]

1438. PJM States disagree, arguing that there is no proposed requirement that retail regulators show why an *ex ante* approach is inappropriate before agreeing to and advocating for an alternate. PJM States further assert that allowing states to agree on an alternate cost allocation approach after seeing what transmission projects are selected may be beneficial since states will have more information on specific projects.[3055]

1439. Some commenters seek clarification on the NOPR proposal. Pennsylvania Commission explains that because this negotiation would occur after transmission facility selection, it is an *ex post* "State Agreement Process." As such, Pennsylvania Commission contends, it could create confusion if the Commission does not clarify that different rules apply to the 90-day "renegotiation" process.[3056] Similarly, MISO states that it is not clear whether the proposed requirements are intended as an alternative to the State Agreement Process or to define how the State Agreement Process would be implemented.[3057]

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[3054] PJM Initial Comments at 117.

[3055] PJM States Reply Comments at 6.

[3056] Pennsylvania Commission Initial Comments at 15.

[3057] MISO Initial Comments at 71.

1440. Some commenters oppose a requirement to provide a time period for a state or states to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected in the regional transmission plan that is different than any *ex ante* regional cost allocation method (i.e., Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply.[3058] Dominion and Idaho Power argue that the Commission should permit regional flexibility as to whether to adopt such a time period.[3059] Idaho Power further contends that the Commission's transmission planning processes are not the primary barriers to transmission development; instead, federal permitting and siting processes and coordination with stakeholders are greater barriers.[3060]

1441. MISO recommends that rather than requiring the specific process and *ex post* opportunities for states to negotiate an alternate cost allocation method, the Commission should identify the opportunity for state involvement in the development of cost allocation and leave the details for that involvement to each transmission planning region.[3061] Pennsylvania Commission states that it does not view the time period for

[3058] Dominion Initial Comments at 51; Idaho Power Initial Comments at 10-11; PPL Initial Comments at 27.

[3059] Dominion Initial Comments at 51; Idaho Power Initial Comments at 10-11.

[3060] Idaho Power Initial Comments at 11 (noting National Environmental Policy Act review and siting decisions with the Bureau of Land Management as examples of federal permitting and siting processes).

[3061] MISO Initial Comments at 71.

state-negotiated alternate cost allocation as a principal negotiation method for cost allocation and asserts that more appropriate processes are the proposed State Agreement Process or PJM's existing State Agreement Approach.[3062]

1442. Dominion supports allowing but not requiring that *ex ante* processes be coupled with an option for states to propose an alternate method, stating that the process for establishing an alternative cost allocation method could become cumbersome as the NOPR proposes to require it to comply with the six Order No. 1000 regional cost allocation principles.[3063] Exelon recommends allowing states the opportunity to propose an alternative cost allocation method to the *ex ante* method after transmission project selection, but states that FPA section 205 rights holders should be able to accept, modify, or reject the proposed alternative cost allocation method. Exelon claims that this approach would respect the legal rights of transmission owners, pointing to PJM's State Agreement Approach as an example.[3064] NESCOE urges the Commission to reject Exelon's request that transmission providers be free to accept or reject cost allocation methods proposed by state entities.[3065]

[3062] Pennsylvania Commission Initial Comments at 16.

[3063] Dominion Initial Comments at 51.

[3064] Exelon Initial Comments at 26-27.

[3065] NESCOE Reply Comments at 3-4.

### i. Permissive Right of Transmission Provider to File Alternate Cost Allocation Method with the Commission upon Unanimous State Agreement

1443. NARUC and NESCOE argue that if states unanimously agree on an alternate cost allocation method, then the transmission provider should be obligated to file it.[3066] NARUC states that the transmission provider may also file the cost allocation method that would otherwise apply if it concludes that the negotiated cost allocation method does not comply with the six Order No. 1000 regional cost allocation principles or is otherwise deficient. NARUC contends that this approach would not violate the transmission providers' FPA section 205 filing rights.[3067] Similarly, NESCOE asserts that the Commission should allow the transmission provider to file its preferred approach, but also require that the transmission provider file the state-negotiated alternate cost allocation method, an approach that could be modeled after existing provisions in NYISO and SPP.[3068]

1444. NESCOE also requests that the Commission clarify whether unanimity means that each opting-in state has agreed to fund the Long-Term Regional Transmission Facility or that all the states in the transmission planning region have agreed that a subset of states will fund the Long-Term Regional Transmission Facility.[3069] NESCOE further requests

[3066] NARUC Initial Comments at 53; NESCOE Initial Comments at 68.

[3067] NARUC Initial Comments at 53.

[3068] NESCOE Initial Comments at 68-70.

[3069] *Id.* at 10, 67-68.

that the Commission clarify how it intends to reconcile the unanimous agreement requirement in this proposal with the other NOPR proposal that gives states the ability to choose the definition of state agreement for purposes of a cost allocation method and where the NOPR expressed a willingness to abide by the bylaws of an individual regional state committee, which may not define agreement as full unanimity.[3070]

1445. Indiana Commission expresses concern that the requirement to obtain unanimous state approval regarding an *ex post* cost allocation process might prove unworkable. Indiana Commission argues that it may be unrealistic to expect that states can reach unanimity on something as contentious as cost allocation. Moreover, Indiana Commission is concerned that states may use the requirement for unanimous agreement to leverage their vote and to gain ground in other areas of contention.[3071]

1446. PIOs seek clarification on the intent behind the NOPR language that "the public utility transmission provider *may elect* to file [a state-negotiated alternate cost allocation method] with the Commission for consideration under FPA section 205."[3072] Similarly, Pennsylvania Commission and PJM States request clarification regarding whether transmission providers could choose not to file an alternative cost allocation method to which the states in a transmission planning region have unanimously agreed.[3073]

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[3070] *Id.* at 68 (citing NOPR, 179 FERC ¶ 61,028 at P 306 & n.512).

[3071] Indiana Commission Initial Comments at 5.

[3072] PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

[3073] Pennsylvania Commission Initial Comments at 16-17; PJM States Reply

Pennsylvania Commission asserts that it sees no reason why a transmission provider should be able to override the unanimous agreement of affected states.[3074]

1447. In addition, PJM States recommend that to address the inability for states to voice their cost allocation concerns, the Commission should consider how it can afford retail regulators greater participation status in the FPA section 205 filing process.[3075] Further, PJM States note that other regional states committees have varying processes, including the ability to request that a transmission provider file a cost allocation method on their behalf.[3076]

### ii. Duration for the Time Period for State-negotiated Cost Allocation

1448. A few commenters agree with the Commission's proposal to require a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.[3077] For example, New England for Offshore Wind states that it is essential that deadlines are imposed to prevent delays caused by disagreements over cost allocation.[3078] PIOs assert

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Comments at 6.

[3074] Pennsylvania Commission Initial Comments at 17.

[3075] PJM States Reply Comments at 6-7.

[3076] *Id.* at 7.

[3077] New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

[3078] New England for Offshore Wind Initial Comments at 5.

that the 90-day time period should begin when the transmission project or portfolio of projects is selected.[3079]

1449. Many commenters, however, argue that the 90-day time period is too short. For example, NARUC, National Grid, and Southern contend that 90 days may be insufficient time for the states in large, multi-state transmission planning regions to negotiate a cost allocation method.[3080] Similarly, NRG argues that the Commission might consider alternative timelines for multi-state collaboration versus where there is a single state entity responsible for the cost allocation.[3081] US Chamber of Commerce contends that the 90-day timeline for state-negotiated cost allocation agreements is unreasonably tight and may undermine the potential for agreement.[3082]

1450. Several commenters, including state commissions, propose longer time periods. For example, California Commission, Kentucky Commission Chair Chandler, Louisiana Commission, NARUC, NRG, and Pacific Northwest State Agencies propose at least six months (180 days) as a more appropriate time period for state negotiation.[3083] California

[3079] PIOs Initial Comments at 70.

[3080] NARUC Initial Comments at 52-53; National Grid Initial Comments at 24-25; Southern Initial Comments at 7-8.

[3081] NRG Initial Comments at 21.

[3082] US Chamber of Commerce Initial Comments at 10.

[3083] California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial Comments at 34-35; NARUC Initial Comments at 52-53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27-28.

Commission and Louisiana Commission request that states should be provided with the opportunity to request extensions if they fail to agree on a cost allocation method after six months (180 days).[3084] OMS recommends that the Commission establish periodic reporting requirements for transmission providers during the 90-day period with an option to extend the deliberations for good cause.[3085]

1451. Several other commenters contend that it should be left to the transmission planning regions, with input from states, to determine the appropriate time period.[3086] For example, Dominion states that the Commission should not dictate any particular timetable and should instead evaluate proposals on a case-by-case basis.[3087] Similarly, Nevada Commission proposes that the Commission require relevant state agencies to be involved in the process as early as possible, but to provide no less than 120 days to allow for appropriate notice and review of any state-negotiated agreement.[3088] Exelon, Indiana Commission, and SERTP Sponsors recommend allowing flexibility in determining the

[3084] California Commission Initial Comments at 56; Louisiana Commission Initial Comments at 35.

[3085] OMS Initial Comments at 13.

[3086] Dominion Initial Comments at 51-52; Exelon Initial Comments at 28-29; Indiana Commission Initial Comments at 5-6; National Grid Initial Comments at 24-25; NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12-13; SERTP Sponsors Initial Comments at 15.

[3087] Dominion Initial Comments at 51-52.

[3088] Nevada Commission Initial Comments at 13-14.

appropriate time period to reflect regional differences.[3089] Idaho Power agrees but cautions that any process should not extend the length of transmission planning processes or development.[3090] Pennsylvania Commission also supports flexibility in determining the appropriate time period given that this process is new and there is little knowledge and experience with respect to how it will function in practice.[3091]

1452. NESCOE and PJM States assert that NYISO's process referenced by the Commission can last longer than the 90-day time period for state-negotiated cost allocation proposed in the NOPR.[3092] Further, NESCOE emphasizes that the NYISO process involves only one state entity, whereas other transmission planning regions have multiple states. Thus, NESCOE and PJM States argue, the Commission should allow transmission planning regions to determine what time period is appropriate.[3093]

1453. A few other commenters contend that state negotiation on an alternate cost allocation method should not be limited by any time period. For example, PPL asserts that limiting the timeframe merely lowers the chance of state agreement, and thus the

[3089] Exelon Initial Comments at 28-29; Indiana Commission Initial Comments at 5-6; SERTP Sponsors Initial Comments at 15.

[3090] Idaho Power Initial Comments at 10-11.

[3091] Pennsylvania Commission Initial Comments at 16.

[3092] NESCOE Initial Comments at 70-71 (citing NOPR, 179 FERC ¶ 61,028 at P 323); PJM States Initial Comments at 12-13 (citing *N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,040, at PP 119-121 (2015)).

[3093] NESCOE Initial Comments at 71; PJM States Initial Comments at 12-13.

prospects for the underlying transmission project to be constructed.[3094] Southern states that the Commission should allow transmission planning regions to develop a process that has state support.[3095] Similarly, Xcel contends that transmission planning regions should have as much time as needed to negotiate and identify cost allocation methods.[3096]

### iii. Other Issues

1454. NESCOE, Northwest and Intermountain, PJM, and SEIA agree with the proposal that if states cannot unanimously agree on an alternate cost allocation method within the specified timeframe, then the transmission developer would be entitled to use the cost allocation method that would otherwise apply for that Long-Term Regional Transmission Facility.[3097] In contrast, NRG recommends that in the case where states do not agree, the Commission could either require the transmission provider to make a filing or subject rival state filings to "jump ball" treatment. NRG contends that either of these approaches would encourage comity and resolution of states' differences.[3098]

1455. MISO and PPL oppose establishing a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes. MISO

[3094] PPL Initial Comments at 27.

[3095] Southern Initial Comments at 7-8.

[3096] Xcel Initial Comments at 11-12.

[3097] NESCOE Initial Comments at 70; Northwest and Intermountain Initial Comments at 19; PJM Initial Comments at 117-118; SEIA Initial Comments at 24.

[3098] NRG Initial Comments at 21.

states that there is no evidence in the record of this proceeding to support extending the state involvement proposed in the NOPR to existing near-term transmission planning processes.[3099] PPL argues that departures from an *ex ante* cost allocation method would lead to uncertainty, delay, and costly litigation.[3100]

### c. Commission Determination

1456. We decline to adopt the NOPR proposal to require transmission providers to provide a time period after selection of Long-Term Regional Transmission Facilities for states to negotiate an alternate cost allocation that is different than any *ex ante* regional cost allocation method that would otherwise apply. We find that requiring a time period after selection for states to negotiate an alternate *ex post* cost allocation method is largely duplicative given our decision above to allow the use of a State Agreement Process before or after the selection of a Long-Term Regional Transmission Facility (or a portfolio of such Facilities). Furthermore, having two separate processes that serve similar functions could add unnecessary complexity and create confusion in the cost allocation process.[3101] Relevant State Entities will have an opportunity to provide input

[3099] MISO Initial Comments at 71.

[3100] PPL Initial Comments at 27-28.

[3101] *See, e.g.*, MISO Initial Comments at 71 (seeking clarification as to whether the proposed time period for states to negotiate cost allocation is an alternative to the State Agreement Process); Pennsylvania Commission Initial Comments at 16 (stating that it does not view the proposed time period as the principal method for negotiating cost allocation and that the more appropriate process is the proposed State Agreement Process).

on and to potentially agree to a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process as part of the Engagement Period that we require transmission providers to establish. We are also concerned that the burden associated with the NOPR proposal would have been significant, as it would have created a requirement to allow for such negotiations for all Long-Term Regional Transmission Facilities.

1457. Because we are declining to require that transmission providers establish a time period after selection of Long-Term Regional Transmission Facilities to allow states to negotiate an alternate *ex post* cost allocation method, we need not address the comments on the duration of such a time period and the requests for clarification by MISO, Pennsylvania Commission, PIOs, and PJM States.[3102]

### B. Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Order No. 1000 Regional Cost Allocation Principles

#### 1. NOPR Proposal

1458. The Commission proposed to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities comply with the existing six Order No. 1000 regional cost allocation principles.[3103] The six regional

[3102] MISO Initial Comments at 71; Pennsylvania Commission Initial Comments at 15; PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319); PJM States Reply Comments at 6.

[3103] NOPR, 179 FERC ¶ 61,028 at P 302.

transmission cost allocation principles adopted in Order No. 1000 are: (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[3104]

### 2. Comments

#### a. General Proposal

1459. Some commenters agree with the Commission's proposal that any Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities must comply with the existing six Order No. 1000 regional cost allocation principles.[3105]

[3104] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[3105] APPA Initial Comments at 40; Dominion Initial Comments at 45; Kentucky Commission Chair Chandler Initial Comments at 3; NESCOE Initial Comments at 56; NRECA Initial Comments at 56; Ohio Consumers Initial Comments at 12-13.

APPA requests that the Commission clarify that it is not requiring changes to existing Commission-approved Order No. 1000 regional cost allocation principles.[3106]

1460. New Jersey Commission supports requiring that any negotiated cost allocation method, whether *ex ante* or *ex post*, comply with the Order No. 1000 regional cost allocation principles, except for Principle 4.[3107] New Jersey Commission opines that requiring that cost allocation methods be consistent with the beneficiary-pays principle is particularly necessary in a State Agreement Process to avoid potential free ridership.[3108]

1461. Industrial Customers argue that, regardless of the cost allocation method that is chosen, the Commission should explicitly state that the cost causation principle must apply, as compliance with Order No. 1000 may not ensure compliance with cost causation principles on its own.[3109] Large Public Power argues that the Commission must hew closely to the first two principles governing cost allocation articulated in Order No. 1000: (1) that costs must be allocated in a way that is roughly commensurate with benefits; and (2) that there will be no involuntary allocation of costs to non-

[3106] APPA Initial Comments at 5.

[3107] New Jersey Commission Initial Comments at 18 (citing New Jersey Commission ANOPR Comments at 7-8 (explaining why it opposes Principle 4's policy of allowing beneficiaries in other transmission planning regions to evade all cost allocation for transmission projects that provide them with substantial benefits)).

[3108] *Id.*

[3109] Industrial Customers Initial Comments at 23-24.

beneficiaries.[3110] Pine Gate asserts that transmission providers must be required to propose cost allocation methods that comport with the well-established "roughly commensurate" principle.[3111] City of New Orleans Council and Ohio Commission Federal Advocate state that cost allocation must adhere to cost causation and beneficiary-pays principles.[3112]

1462. OMS states that it developed its own principles through a committee of regulators focused on cost allocation for long-range transmission projects in response to the NOPR, which include: (1) costs of new transmission projects should be allocated to cost causers and beneficiaries in a manner roughly commensurate with the costs caused and benefits of those projects; (2) cost allocation should be as granular and accurate as possible such that benefit-cost analysis uses metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking; (3) costs should not be allocated to parties that receive negligible or negative benefits; and (4) generators and load each can be considered cost causers, beneficiaries, or both and should be allocated costs accordingly.[3113] Louisiana Commission supports OMS' position on benefit metrics as articulated in OMS' second

[3110] Large Public Power Initial Comments at 29.

[3111] Pine Gate Initial Comments at 42-44.

[3112] City of New Orleans Council Initial Comments at 10; Ohio Commission Federal Advocate Initial Comments at 14.

[3113] OMS Initial Comments at 12.

principle.[3114] OMS highlights that regional flexibility must be preserved, pointing to MISO's Targeted Market Efficiency Projects process as an example of a process that did not strictly comply with Order No. 1000 but was effective and widely supported.[3115]

1463. Ohio Consumers argue that the Commission should espouse three fundamental principles when considering the benefits and cost allocations associated with any Long-Term Regional Transmission Facilities: (1) costs should be allocated to those who caused the costs to be incurred; (2) subsidies are bad for competitive markets, because they result in noncompetitive outcomes and inaccurate price signals; and (3) consumers should not be charged until transmission projects are found to be used and useful.[3116] Also, Ohio Consumers assert, cost allocations to consumers should adhere to the Commission's current ratemaking standards in PJM.[3117]

1464. PIOs assert that the Commission should require that transmission providers demonstrate on compliance that the cost allocation method complies with the beneficiary-pays principle by considering all quantifiable benefits.[3118] ELCON states that cost allocation proposals must comply with the cost causation principle "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."

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[3114] Louisiana Commission Reply Comments at 10.

[3115] OMS Initial Comments at 13.

[3116] Ohio Consumers Initial Comments at 6-7, 12-14.

[3117] *Id.* at 1.

[3118] PIOs Initial Comments at 68.

ELCON remains concerned that, in an effort to reach public policy goals, costs will be socialized among all consumers without consideration of the cost causers, and states that cost allocation must evaluate the drivers of the specific transmission need and the party that caused the need for the additional transmission.[3119] Utah Division of Public Utilities asks that when states or other stakeholders disagree on the cost allocation method due to differing renewable goals, the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of the proposed transmission projects are due to state policies.[3120]

1465. West Virginia Commission states that it supports retention of the cost-causation principles in Order No. 1000, noting that the Order No. 1000 cost allocation principles are grounded in the beneficiary-pays principle that the costs of transmission facilities should be allocated commensurate with the benefits of those facilities. However, West Virginia Commission contends that the beneficiary-pays principle cannot and should not be applied on a presumptive regional basis when new transmission is identified as needed to accommodate one or more states' public policy decisions.[3121] West Virginia Commission states that longstanding legal precedent on cost causation and ratemaking principles require that rates remain just and reasonable, that customers pay for

[3119] ELCON Initial Comments at 15.

[3120] Utah Division of Public Utilities Initial Comments at 9-10.

[3121] West Virginia Commission Reply Comments at 3; West Virginia Commission Supplemental Comments at 3-4.

transmission upgrades based upon their roughly commensurate benefits, and that new generators, or the willing and voluntary benefactors of new generators, pay the costs for the interconnection-related network upgrades if such upgrades would not be needed but for the new generators.[3122] West Virginia Commission contends that to adopt a cost allocation that requires any non-volunteering state to pay costs caused by another state's public policies would depart from years of Commission precedent and would be unjust and unreasonable.[3123]

1466. Vermont Electric and Vermont Transco encourage the Commission to ensure that any cost allocation approach ensures that the benefits of transmission facilities are roughly commensurate with the costs thereof for both small rural states and larger, more populated states. Vermont Electric and Vermont Transco argue that the final rule should reflect equitable principles in accordance with which the significant investments made by Vermont prior to the issuance of the final rule are taken into account in cost allocation processes.[3124] MISO states that the final rule should not preclude applying different cost allocation methods to transmission projects of the same type, noting that Order No. 2000

[3122] West Virginia Commission Reply Comments at 6 (citing *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *ICC v. FERC I*, 576 F.3d at 477; *ISO New England, Inc.*, 115 FERC ¶ 61,145, at P 13 (2006), *aff'd, TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (D.C. Cir. 2015); *El Paso Elec. Co. v. FERC*, 832 F.3d 495, 499-500 & n.10 (5th Cir. 2016); *Midcontinent Indep. Sys. Operator, Inc.*, 159 FERC ¶ 63,016, at P 138 (2017), *aff'd*, 164 FERC ¶ 61,194 (2018); Order No. 1000, 136 FERC ¶ 61,051 at P 622); West Virginia Commission Supplemental Comments at 5-6.

[3123] West Virginia Commission Reply Comments at 6-7.

[3124] Vermont Electric and Vermont Transco Initial Comments at 3-4.

contemplated "the potential for different cost allocation methodologies" as RTO/ISO footprints grew.[3125]

**b. Comments Specific to A State Agreement Process**

1467. Certain commenters discuss the interaction between the Order No. 1000 regional cost allocation principles and any cost allocation methods resulting from the State Agreement Process. Pennsylvania Commission supports the proposed requirement while also contending that the Commission should defer to unanimous agreement by affected states.[3126] Avangrid argues that the Commission should relax this requirement and defer to the balance achieved via state agreement.[3127] Mississippi Commission argues that the proposed requirement is unnecessary because the State Agreement Process will result in voluntary assumption of costs.[3128] Likewise, PacifiCorp and NV Energy argue that the Order No. 1000 regional cost allocation principles should not apply to the State Agreement Process because there will be no involuntary cost allocation given that states have already agreed. They further contend that beneficiary analyses and minimum cost-benefit ratios will foreclose state-favored cost allocation solutions.[3129] PacifiCorp and

[3125] MISO Reply Comments at 17-19.

[3126] Pennsylvania Commission Initial Comments at 13.

[3127] Avangrid Initial Comments at 30.

[3128] Mississippi Commission Initial Comments at 25.

[3129] PacifiCorp and NV Energy Initial Comments at 17.

NV Energy argue that agreeing to cost allocation will be a difficult task for states, and the Commission should not further dictate the type of agreement.[3130]

1468. PJM States ask the Commission not to preclude or limit the availability of the PJM State Agreement Approach, which they assert is not required to comply with the Order No. 1000 regional cost allocation principles.[3131] Similarly, Exelon notes that the Commission has indicated that voluntary state cost allocation agreements need not comply with Order No. 1000.[3132] Therefore, Exelon asks the Commission to clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation.[3133]

### 3. Commission Determination

1469. We adopt the NOPR proposal, with modification, to require Long-Term Regional Transmission Cost Allocation Methods to comply with five of the six existing Order No. 1000 regional cost allocation principles. Specifically, we require transmission providers in each transmission planning region to demonstrate on compliance with this final rule that any Long-Term Regional Transmission Cost Allocation Methods, that they propose

[3130] *Id.*

[3131] PJM States Initial Comments at 11-12 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 142).

[3132] Exelon Initial Comments at 27-28 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 4).

[3133] Exelon Initial Comments at 27-28 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214).

that Relevant State Entities have *not* indicated that they agree to, comply with Order No. 1000 regional cost allocation principles (1) through (5). However, we do not require transmission providers to demonstrate that any Long-Term Regional Transmission Cost Allocation Methods that they propose complies with Order No. 1000 regional cost allocation principle (6), and, as a result, unlike under Order No. 1000, transmission providers cannot adopt different Long-Term Regional Transmission Cost allocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.

1470. However, as discussed further below, we do not adopt the NOPR proposal to require compliance with the Order No. 1000 regional cost allocation principles in two situations. First, we do not require a Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles *if* Relevant State Entities indicate that they agreed to that method as part of the Engagement Period. Second, we do not require a cost allocation method resulting from a State Agreement Process to comply with the Order No. 1000 regional cost allocation principles.

1471. The first five Order No. 1000 regional transmission cost allocation principles are: (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits;[3134] (2) those that receive no benefit from

[3134] Order No. 1000, 136 FERC ¶ 61,051 at P 622.

transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities;[3135] (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1;[3136] (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs;[3137] and (5) the method for determining benefits and identifying beneficiaries must be transparent.[3138]

1472. We find that Order No. 1000 regional cost allocation principles (1) through (5) remain relevant for *ex ante* cost allocation methods for Long-Term Regional Transmission Facilities that transmission providers propose on compliance but with which Relevant State Entities have *not* indicated their agreement. In Order No. 1000, regarding regional cost allocation principle (1), the Commission stated that "[r]equiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts."[3139] Since making that statement, the Commission and the courts have only further strengthened this

[3135] *Id.* P 637.

[3136] *Id.* P 646.

[3137] *Id.* P 657.

[3138] *Id.* P 668.

[3139] *Id.* P 623. *See also id.* P 586 & n.453 (citing *ICC v. FERC I*, 576 F.3d at 476-77; *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004); *Sithe/Indep. Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002)).

connection between beneficiaries-pay cost allocation and the cost causation principle.[3140] Similarly, principle (2) continues to "express[] a central tenet of cost causation" and is "thus essential to proper cost allocation."[3141]

1473. Concerning regional cost allocation principle (3), as noted in Order No. 1000, transmission providers may choose to establish such a threshold to mitigate against uncertainty in the measurement of benefits and costs, and this principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan.[3142] As to regional cost allocation principle (4), this final rule maintains the close link established by Order No. 1000 between regional transmission planning and cost allocation to the region being planned for.[3143] Further, we find, similar to the Commission's findings in Order No. 1000, that removing regional cost allocation principle (4) would be tantamount to interconnection-wide transmission planning because unilateral allocation of costs from one transmission planning region to another would require stakeholders to actively monitor regional transmission planning processes in numerous other regions.[3144] Lastly, we find, similar to Order No. 1000, that

[3140] *Long Island Power Auth. v. FERC*, 27 F.4th 705, 713–14 (D.C. Cir. 2022); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1261-63.

[3141] Order No. 1000, 136 FERC ¶ 61,051 at P 637.

[3142] *Id.* PP 647-648.

[3143] *Id.* P 660. *See also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87-88.

[3144] Order No. 1000, 136 FERC ¶ 61,051 at P 660. *See also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87-88.

regional cost allocation principle (5) will ensure that Long-Term Regional Transmission Cost Allocation Methods are just and reasonable and not unduly discriminatory or preferential, will help aid in development and construction of new transmission, and may avoid contentious litigation or prolonged debate among stakeholders.[3145]

1474. In contrast to the first five regional cost allocation principles, Order No. 1000 regional cost allocation principle (6) is inconsistent with Long-Term Regional Transmission Planning as directed in this final rule. Order No. 1000 Regional cost allocation principle (6) provides that there may be different regional cost allocation methods for different types of transmission facilities in the regional transmission plan but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance.[3146] As we explain below, however, transmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types. Permitting such project-type-limited Long-Term Regional Transmission Cost Allocation Methods would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final rule. Accordingly, in declining to require that Long-Term Regional Transmission Cost Allocation Methods comply with

[3145] Order No. 1000, 136 FERC ¶ 61,051 at P 669.

[3146] *Id.* P 685.

Order No. 1000 regional cost allocation principle (6), consistent with the request of some commenters,[3147] we find that reliability, economic, or public policy transmission facility types reflect a more siloed approach to regional transmission planning that is misaligned with our Long-Term Regional Transmission Planning reforms and would likely lead to the allocation of the costs of Long-Term Regional Transmission Facilities in a manner that is not at least roughly commensurate with estimated benefits.

1475. We clarify that this final rule does not preclude the adoption of multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection, i.e., is an *ex ante* cost allocation method, and does not allocate costs by project type. We find that knowing the applicability of a Long-Term Regional Transmission Cost Allocation Method in advance is inherent to the definition of, and one of the primary reasons for, requiring transmission providers to include an *ex ante* cost allocation method in their OATTs. As such, transmission providers that choose to propose more than one Long-Term Regional Transmission Cost Allocation Method on compliance are required to make clear in their OATTs which Long-Term Regional Transmission Cost Allocation Method applies to which Long-Term Regional Transmission Facilities (e.g., cost allocation methods that apply to Long-Term Regional Transmission Facilities above a

[3147] Massachusetts Attorney General Initial Comments at 15, 21; Ørsted Initial Comments at 9.

certain voltage threshold or to Long-Term Regional Transmission Facilities located within a specific portion of a transmission planning region's footprint).[3148] However, we emphasize that any Long-Term Regional Transmission Cost Allocation Method that transmission providers propose, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, must comply with Order No. 1000 regional cost allocation principles (1) through (5) and the other requirements of this final rule.

1476. Regarding cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and asked transmission providers to file after the Engagement Period, the Commission has previously found that "Order No. 1000 allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s)."[3149] Additionally, where transmission providers have proposed cost allocation methods corresponding to such voluntary arrangements, the Commission has held that it need not find that those cost allocation methods comply with Order No. 1000.[3150] Consistent with

[3148] We believe that this finding should address MISO's request that the final rule not preclude applying different cost allocation methods to projects of the same type.

[3149] *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 561, 724; Order No. 1000-A, 139 FERC ¶ 61,132 at PP 728-729).

[3150] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142-143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 121; *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106, at PP 48-50

this precedent, we find that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file also qualify as voluntary alternative cost sharing arrangements and, accordingly, we decline to require those methods to adhere to the six Order No. 1000 regional cost allocation principles. However, those methods must still comply with the cost causation principle and any other legal requirements for cost allocation.

1477. We decline to adopt the NOPR proposal that required adherence to the six Order No. 1000 regional cost allocation principles because cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to are likely to facilitate agreement over development of such Long-Term Regional Transmission Facilities by, for example, making the Relevant State Entities more confident that customers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities and by reducing the likelihood that selected Long-Term Regional Transmission Facilities cannot be constructed because they do not receive necessary state regulatory approvals. Affording additional flexibility for these methods may encourage their use, which would facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. However, as described in the next section, we note that cost allocation methods resulting from a State Agreement

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Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to must be just and reasonable and not unduly discriminatory or preferential and must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[3151]

1478. ELCON and West Virginia Commission express concern that the NOPR's proposals for cost allocation methods, including requiring compliance with the six Order No. 1000 regional cost allocation principles, might not sufficiently recognize specific Public Policy Requirements as driving the needs for specific Long-Term Regional Transmission Facilities and, therefore, allow cost allocation methods that contradict precedent on cost causation. Similarly, Utah Division of Public Utilities asks that the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of Long-Term Regional Transmission Facilities are due to state policies when states or other stakeholders disagree on the cost allocation method due to differing renewable goals. We believe these concerns are misplaced and no further requirements are necessary. First, while state laws, regulations, and goals make up some of the drivers of Long-Term Transmission Needs, they do not comprise the entirety of those needs, as described in the Development of Long-Term Scenarios section of this final rule. Second, as described below, all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs to transmission customers in a manner that is at least roughly commensurate with their

[3151] *See, e.g.*, *PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178 at P 33.

estimated benefits. Third, for Long-Term Regional Transmission Cost Allocation Methods, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, compliance with five of the Order No. 1000 regional cost allocation principles further safeguards against cost causation concerns; notably, principles (1) and (2) require that benefits received are at least roughly commensurate with costs paid and that costs may not be involuntarily allocated to those that do not benefit, respectively. Further, Order No. 1000 regional cost allocation principle (5), as well as the requirements in this final rule to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities, ensures sufficient transparency for stakeholders to understand how the costs of selected Long-Term Regional Transmission Facilities will be allocated to transmission customers in relation to the benefits that they are forecasted to provide. Lastly, for cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities have agreed to and asked transmission providers to file, we believe that states will have an opportunity to come to consensus on cost allocation methods that they perceive as allocating costs in a manner that is at least roughly commensurate with estimated benefits.

1479. Regarding Vermont Electric and Vermont Transco's concern regarding possible discrepancies between benefits received by small rural states and larger, more populated states, we believe that our requirement that all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs in a manner that is at least roughly commensurate with estimated benefits addresses this concern. Regarding OMS's,

Louisiana Commission's, and Ohio Consumers' requests that the Commission adopt certain cost allocation principles distinct from the six Order No. 1000 regional cost allocation principles, the Commission did not propose adoption of any additional principles or that the six Order No. 1000 regional cost allocation principles be substituted for others. Accordingly, we find these requests beyond the scope of this final rule. Additionally, in response to Exelon's request that the Commission clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation,[3152] we clarify that any State Agreement Process that the Commission accepts in compliance with this final rule will apply to only Long-Term Regional Transmission Facilities, while any existing voluntary state cost allocation processes that the Commission has previously accepted apply to other transmission facilities and, thus, are unaltered by this final rule.

### C. Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities

#### 1. NOPR Proposal

1480. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet

[3152] Exelon Initial Comments at 27-28.

identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers must explain the rationale for using the benefits identified.[3153] The Commission also requested comment on whether the Commission should require that transmission providers account for the full list of benefits, as described in the Evaluation of the Benefits of Regional Transmission Facilities section above, in Long-Term Regional Transmission Planning, or whether no change to the benefits currently used in existing regional transmission planning processes is needed.[3154]

1481. The Commission also proposed, for purposes of cost allocation, to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.[3155]

[3153] NOPR, 179 FERC ¶ 61,028 at P 326.

[3154] *Id.* P 327.

[3155] *Id.* P 228.

### 2. Comments

#### a. Agree with Proposal

1482. Some commenters agree with the NOPR proposal.[3156] NESCOE contends that it is critical that costs as well as benefits be clearly identified in connection with project evaluation.[3157]

1483. Many commenters supporting the proposal emphasize the importance of flexibility and the lack of a proposed requirement in the NOPR to require that specific benefits be accounted for in cost allocation.[3158] Dominion opposes making the NOPR's listed benefits mandatory for cost allocation because identifying and measuring them would be difficult and lead to disputes and litigation that would add to the costs, borne by consumers, of transmission development.[3159] NYISO states that considering the list of benefits in the NOPR in cost allocation would introduce significant complexity and create

[3156] Avangrid Initial Comments at 29; California Energy Commission Initial Comments at 3; Idaho Power Initial Comments at 11; ITC Initial Comments at 30; NESCOE Initial Comments at 72; Northwest and Intermountain Initial Comments at 18-19.

[3157] NESCOE Initial Comments at 72.

[3158] APPA Initial Comments at 46; Dominion Initial Comments at 45-46; Dominion Reply Comments at 6, 9; Exelon Initial Comments at 29-30 (citing NOPR, 179 FERC ¶ 61,028 at P 312 & n.516; *Midwest ISO Transmission Owners*, 373 F.3d at 1369); Louisiana Commission Initial Comments at 35-36; NARUC Initial Comments at 38; National Grid Initial Comments at 26-27; NYISO Initial Comments at 51-52; Pacific Northwest Utilities Initial Comments at 8-9; PPL Initial Comments at 28; SERTP Sponsors Initial Comments at 30-31; Southern Initial Comments at 27; Xcel Initial Comments at 12.

[3159] Dominion Reply Comments at 6-7.

a burdensome and perhaps infeasible process.[3160] Xcel states that not all benefits need to be studied given that such study can be costly and add little value, and that the analysis of future benefits should balance uncertainties to ensure that it is not too speculative.[3161]

1484. Pacific Northwest Utilities and SERTP Sponsors argue that many of the NOPR's proposed benefits would work only in RTO/ISO transmission planning regions and are not appropriate in non-RTO/ISO regions.[3162] Pacific Northwest Utilities state that several of the benefits listed in the NOPR do not benefit transmission providers and argue that—in non-RTO/ISO transmission planning regions, like NorthernGrid, where there is neither a single independent transmission system operator nor any single independent transmission provider through which to affect transmission rate impacts due to cost allocation—costs allocated to transmission providers must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities.[3163] California Municipal Utilities argue that requiring consideration of the list of benefits in the NOPR would not reflect the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and consumer protection against speculative projects.[3164] Louisiana Commission states

[3160] NYISO Initial Comments at 52.

[3161] Xcel Initial Comments at 12.

[3162] Pacific Northwest Utilities Initial Comments at 8-10; SERTP Sponsors Initial Comments at 29-30.

[3163] Pacific Northwest Utilities Initial Comments at 9-10.

[3164] California Municipal Utilities Reply Comments at 5-6 (citing ACEG Initial

that transmission providers and retail regulators should be allowed to develop and agree on an appropriate set of metrics to be used for cost allocation.[3165]

1485. APPA argues that regional flexibility should include allowing transmission providers to demonstrate on compliance that the benefits that they use to allocate the costs of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.[3166] National Grid asserts that flexibility avoids the risk of a static list of benefits becoming outdated, citing as an example the growing numbers of distributed resources in New England driving the need for transmission-level upgrades in New England. National Grid claims that more granular (state-specific or even direct assignment) cost allocation is appropriate for such upgrades.[3167]

1486. City of New Orleans Council, OMS, Louisiana Commission, and Michigan Commission argue that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2, which states that "[c]ost allocation should be as granular and accurate as possible. Benefit-cost analysis should use metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking."[3168] NARUC

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Comments at 26-48, 50-51, 60-63).

[3165] Louisiana Commission Initial Comments at 35.

[3166] APPA Initial Comments at 46.

[3167] National Grid Initial Comments at 26-27.

[3168] City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35-36; Michigan Commission Initial Comments at 9; OMS Initial

similarly asserts that transmission benefits must be verifiable and quantifiable to justify allocating costs to ratepayers.[3169] Likewise, Idaho Power, Pacific Northwest Utilities, and West Virginia Commission state that benefits must be quantifiable and justified, arguing that many benefits in the NOPR proposal would be difficult to quantify, a difficulty, Idaho Power and Pacific Northwest Utilities argue, exacerbated by the proposed 20-year transmission planning horizon.[3170]

1487. West Virginia Commission argues that use of these benefits allows for unfettered discretion by transmission providers to adopt cost allocation methods that do not meet the cost causation principle.[3171]

1488. Southern states that a cost allocation premised on an overly broad, non-quantifiable construction of benefits would likely exceed the Commission's authority because there must be a correlation between the charges proposed and the expected benefits, as articulated by the courts.[3172] Southern states that the Commission must apply

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Comments at 7-8, 14 (citing Organization of MISO States, Inc., *Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects*, https://www.misostates.org/images/PositionStatements/OMS_Position_Statement_of_Principles_Cost_Allocation_for_LRTPs.pdf).

[3169] NARUC Initial Comments at 25, 38.

[3170] Idaho Power Initial Comments at 11; Pacific Northwest Utilities Initial Comments at 6-9; West Virginia Commission Reply Comments at 4.

[3171] West Virginia Commission Reply Comments at 4.

[3172] Southern Initial Comments at 28-30 (citing *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1321 (D.C. Cir. 2004)).

the roughly commensurate standard by determining whether the benefits to the intended beneficiaries are quantifiable and spread evenly across a transmission planning region. Otherwise, Southern states, the Commission must compile a record based on substantial evidence to support the proposed allocation of costs.[3173] Dominion similarly cautions that assignment of costs requires more than generalized articulation of benefits and that the list of benefits in the NOPR are broadly defined and generalized.[3174]

1489. Ohio Consumers state that the Commission should base the benefits attributable to Long-Term Regional Transmission Planning on the electrons to be delivered from generating facilities. Ohio Consumers point out that state consumer advocates disagree as to which benefits should be considered in cost allocation.[3175] Ohio Consumers argue that adopting a broad definition of benefits that includes state decarbonization plans and socialization of some portion of the associated costs across a transmission planning region would violate the Order No. 1000 regional cost allocation principles and the cost causation principle.[3176]

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[3173] *Id.* at 29-30 (citing *ICC v. FERC I*, 576 F.3d at 476‑77; *Ill. Com. Comm'n v. FERC*, 721 F.3d 764, 777 (7th Cir. 2013) (*ICC v. FERC II*); *ICC v. FERC III*, 756 F.3d at 564-565).

[3174] Dominion Initial Comments at 43-44.

[3175] Ohio Consumers Reply Comments at 10.

[3176] Ohio Consumers Reply Comments at 11 (citing DC and MD Offices of People's Counsel Initial Comments at 31, 34, 38-39).

1490. Pennsylvania Commission takes no position on requiring certain benefits to be accounted for in cost allocation, but states that the need for objective, well-defined, and measurable benefits applies not only to transmission planning but also to cost allocation, noting that it is important that customers who pay the costs allocated to them agree that they are paying for real and appreciable benefits.[3177]

#### b. Requests to reflect the full breadth of benefits in cost allocation methods while maintaining flexibility

1491. Some commenters request that transmission providers reflect the full breadth of benefits in cost allocation methods for Long-Term Regional Transmission Facilities while also supporting flexibility.[3178] Vistra asserts that benefits considered in cost allocation should not be confined to a prescriptive list.[3179] NESCOE argues that the Commission should include a list of benefits in the final rule as a required starting point and allow transmission providers to add or subtract benefits from the list on compliance following consultation with states in their transmission planning region.[3180]

#### c. Disagree with Proposal, Mostly Require Benefits

1492. Some commenters disagree with the Commission's proposal, arguing that the Commission should require transmission providers to account for a minimum set of

[3177] Pennsylvania Commission Initial Comments at 11.

[3178] APPA Initial Comments at 45-46; Massachusetts Attorney General Initial Comments at 21; NESCOE Initial Comments at 72; Vistra Initial Comments at 15.

[3179] Vistra Initial Comments at 15.

[3180] NESCOE Initial Comments at 43, 72.

benefits in cost allocation.[3181] Indicated US Senators and Representatives argue that unless all benefits and costs are incorporated into transmission planning and cost allocation, the result will be biased, resulting in unjust and unreasonable costs and cost allocation.[3182] Acadia Center and CLF contend that failure to consider a minimum set of benefits could result in the failure to select transmission projects that would have benefited customers.[3183] Certain TDUs argue that guardrails should be put in place to require transmission providers to adequately define quantifiable benefits and to make transparent their method for identifying benefits; however, Certain TDUs contend that the Commission should require transmission providers to account for, at minimum, production cost savings and avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement, as may be refined by transmission planning regions as necessary.[3184] US Climate Alliance states that each transmission planning region could determine additional categories of benefits most relevant to them.[3185]

[3181] Acadia Center and CLF Initial Comments at 16-19; Certain TDUs Reply Comments at 2-3; Indicated US Senators and Representatives Initial Comments at 2; US Climate Alliance Initial Comments at 2; US Senators Supplemental Comments at 2.

[3182] Indicated US Senators and Representatives Initial Comments at 2.

[3183] Acadia Center and CLF Initial Comments at 16-19.

[3184] Certain TDUs Reply Comments at 2-3.

[3185] US Climate Alliance Initial Comments at 2.

1493. Other commenters that disagree with the Commission's proposal similarly argue for a required minimum set of benefits, but argue that the Commission should require transmission providers to account for the full list of 12 benefits in the NOPR.[3186] ACEG and PIOs state that it would be unjust and unreasonable for transmission providers to allocate costs in a manner that ignores certain benefits or fails to provide a full accounting of those benefits, including, PIOs assert, cost allocation agreed to by states.[3187] PIOs further argue that allowing transmission providers to agree to a cost allocation method that does not reflect all quantifiable benefits would re-introduce the risk of free ridership.[3188]

1494. Clean Energy Buyers state that they support the Commission requiring each transmission provider to either adopt the benefits identified by the Commission to be used for cost allocation for Long-Term Regional Transmission Facilities or demonstrate why the exclusion of any such benefit(s) is just and reasonable. However, Clean Energy Buyers also recommend that the Commission consider how the factors required for Long-

[3186] ACEG Initial Comments at 60; Clean Energy Associations Initial Comments at 20-21, 34; DC and MD Offices of People's Counsel Initial Comments at 20, 34; PIOs Initial Comments at 64-65.

[3187] ACEG Initial Comments at 60-61 (citing *ICC v. FERC I*, 576 F.3d at 477); PIOs Initial Comments at 65; PIOs Reply Comments at 3.

[3188] PIOs Initial Comments at 65.

Term Scenarios will translate into benefits and ensure that there is no double-counting of benefits.[3189]

1495. Southwestern Power Group states that existing regional cost allocation methods do not account for the range of benefits that regional transmission expansion can provide. Consequently, Southwestern Power Group argues, the costs of regional transmission projects are allocated to too few of the beneficiaries, discouraging the development of regional transmission projects.[3190] Environmental Groups argue that the Commission must ensure that any cost allocation method agreed to by states complies with the beneficiary-pays principle by showing that the method considers all quantifiable benefits of transmission.[3191]

1496. SPP states that its regional cost allocation method does not quantify the specific benefits of transmission facilities within each planning assessment but instead analyzes the benefits and costs of facilities approved in multiple assessments in a comprehensive manner. SPP states that potential inequities are not appropriately quantified in a single regional planning assessment cycle because potential imbalances in one cycle may be offset in later cycles or changed because of topology. SPP emphasizes that quantification of whether benefits of transmission facilities are roughly commensurate with allocated costs should be performed through multiple transmission planning cycles that evaluate

[3189] Clean Energy Buyers Initial Comments at 30.

[3190] Southwestern Power Group Initial Comments at 14-15.

[3191] Environmental Groups Supplemental Comments at 2.

project portfolios, citing SPP's Highway-Byway cost allocation method as an example.[3192]

### d. Alignment of Benefits between Transmission Planning and Cost Allocation

1497. Various commenters proffer arguments as to whether benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities must align with the benefits used in cost allocation. For example, SERTP Sponsors state that there could be differences between the types of benefits used for evaluation and selection and those used for cost allocation, asserting that benefits used in cost allocation must be measured in a consistent and objective manner to limit disputes.[3193]

1498. Some commenters argue that the benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities should closely align with, but need not be the same as, those used in cost allocation.[3194] For example, Clean Energy Associations state that close alignment does not preclude regional variation and points to MISO's Multi-Value Projects' and SPP's Highway/Byway projects' cost allocation methods.[3195]

[3192] SPP Initial Comments at 31.

[3193] SERTP Sponsors Initial Comments at 30-31.

[3194] Clean Energy Associations Initial Comments at 34; Cypress Creek Reply Comments at 14-15; Ørsted Initial Comments at 9.

[3195] Clean Energy Associations Initial Comments at 34-35.

1499. Some commenters argue that the same set of benefits used in transmission planning should be used in cost allocation.[3196] DC and MD Offices of People's Counsel and the New Jersey Commission link such a requirement with the beneficiary-pays principle.[3197] New Jersey Commission states that enforcing the beneficiary-pays principle based on all of a transmission project's quantified benefits is necessary to avoid free-rider problems that could arise, especially in the State Agreement Process.[3198] Additionally, New Jersey Commission states, the policy of preventing states from involuntarily bearing the costs of others' policies must not require states to always pay the full cost of any transmission solution that supports their public policies or prevent states from committing to paying more than what they perceive to be their fair share to overcome disagreements over who will benefit.[3199] Similarly, BP recommends requiring that those benefitting from transmission facilities that meet policy objectives, but without

[3196] DC and MD Offices of People's Counsel Initial Comments at 34; Fervo Reply Comments at 2-3; New Jersey Commission Initial Comments at 18-23; SEIA Initial Comments at 24; Vermont Electric and Vermont Transco Initial Comments at 4; WATT Coalition Initial Comments at 8.

[3197] DC and MD Offices of People's Counsel Initial Comments at 34 (citing *ICC v. FERC I*, 576 F.3d 470; *ICC v. FERC II*, 721 F.3d 764; *ICC v. FERC III*, 756 F.3d 556); New Jersey Commission Initial Comments at 18-23 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1262-63; *Entergy Ark. v. FERC*, 40 F.4th 689, 701 (D.C. Cir. 2022)).

[3198] New Jersey Commission Initial Comments at 18.

[3199] *Id.* at 21-23.

similar policies themselves, be allocated an appropriate share of costs to avoid free ridership.[3200]

1500. Massachusetts Attorney General states that *ex ante* cost allocation methods should reflect the same benefits considered in Long-Term Regional Transmission Planning and not consider benefits in silos.[3201] Ørsted similarly supports a requirement that transmission providers adopt cost allocation methods that recognize the full breadth of benefits that transmission facilities provide.[3202]

1501. PIOs argue that cost allocation is necessarily implicated in the NOPR's preliminary finding that failure to consider a broader set of benefits and beneficiaries of transmission facilities may result in unjust, unreasonable, and unduly discriminatory or preferential rates, reasoning that cost allocation cannot be based on unlawful identification of benefits and beneficiaries.[3203]

**e. Additional Benefits or Suggestions for Refinement**

1502. DC and MD Offices of People's Counsel recommend that the Commission allow Relevant State Entities to propose additional benefit categories for evaluation and to consent to the allocation of costs that align with these additional benefits. At a minimum,

[3200] BP Initial Comments at 9-12.

[3201] Massachusetts Attorney General Initial Comments at 21.

[3202] Ørsted Initial Comments at 9.

[3203] PIOs Initial Comments at 71.

DC and MD Offices of People's Counsel argue, costs should be allocated to the benefitting Relevant State Entities.[3204]

1503. California Energy Commission recommends that transmission providers be required to consider equity and environmental justice in the calculation of benefits, including economic, health, and social benefits to disadvantaged communities.[3205] WE ACT recommends that the Commission include non-energy benefits like pollution reduction, health, jobs, and local economic development in the list of benefits that transmission providers should be required to utilize in identifying and evaluating Long-Term Regional Transmission Facility need, selection, and cost allocation.[3206]

1504. Louisiana Commission states that the Commission should permit transmission providers to consider allocations to all cost causers and beneficiaries, including generators.[3207] Vistra argues that if achieving voluntary corporate and utility clean energy goals is factored into demand driving the need for an upgrade, then the costs of such upgrades should not be assigned to regional load.[3208]

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[3204] DC and MD Offices of People's Counsel Initial Comments at 34.

[3205] California Energy Commission Initial Comments at 3.

[3206] WE ACT Initial Comments at 5.

[3207] Louisiana Commission Initial Comments at 32.

[3208] Vistra Initial Comments at 21-22.

### 3. Commission Determination

1505. We decline to adopt the NOPR proposal to require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.

1506. Instead, as we discuss above in the Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Order No. 1000 Regional Cost Allocation Principles section, we require transmission providers in each transmission planning region to demonstrate on compliance that the required Long-Term Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (i.e., reliability, economic, or transmission needs driven by Public Policy Requirements). While we do not require that cost allocation methods resulting from State Agreement Processes or Long-Term Regional Transmission Cost Allocation Methods that Relevant States Entities indicate they agreed to, must comply with any of the Order No. 1000 regional cost allocation principles, if filed with the Commission, transmission providers must nonetheless demonstrate that either of these types of cost allocation methods will allocate costs in a manner at least roughly commensurate with estimated benefits.[3209] We do not

[3209] *See ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564.

require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission. We adopt this modified approach to the relationship of benefits used in Long-Term Regional Transmission Planning and Long-Term Regional Transmission Cost Allocation Methods because it provides transmission providers with flexibility to propose a Long-Term Regional Transmission Cost Allocation Method(s), allowing for negotiation in the Engagement Period, which we believe will increase the chances that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective regional transmission solution will be developed. At the same time, the requirements in this final rule to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities will provide transparency and help to ensure a cost allocation is just and reasonable.

1507. We note that this flexible approach is consistent with the approach that the Commission took in Order No. 1000 and in subsequent orders on transmission providers' Order No. 1000 compliance filings, where the Commission allowed a wide variety of cost allocation methods and did not require that such methods specifically account for all benefits used in evaluation and selection processes.[3210] The cost allocation method for MISO's Multi-Value Projects and the SPP Highway/Byway cost allocation method are examples that reflect the flexibility that transmission providers have had in adopting cost

[3210] Order No. 1000, 136 FERC ¶ 61,051 at PP 560, 624.

allocation methods suited to their circumstances and that may not have been possible under a less flexible approach.

1508. The one exception to that flexibility, however, is the second component of our compliance requirement, that transmission providers must not allocate costs based on project types; namely, reliability, economic, or Public Policy Requirements needs-driven cost allocation methods. As described in the Long-Term Regional Transmission Facility Cost Allocation Compliance with Existing Six Order No. 1000 Regional Cost Allocation Principles section, we adopt this requirement because permitting such project-type-limited cost allocation methods for Long-Term Regional Transmission Facilities would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final rule. As we note above in the Need for Reform section, allocating costs based on these project types would result in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Allocating costs based on these project types could, for example, encourage the selection of transmission facilities based on either their economic or reliability benefits alone rather than based on an evaluation of the wider range of benefits that they may provide. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments. We further find that permitting the use of such project-type-limited cost

allocation methods for Long-Term Transmission Facilities would not allocate costs in a manner that is at least roughly commensurate to estimated benefits.

1509. We decline to adopt the NOPR proposal to require transmission providers to evaluate benefits over a 20-year time horizon for Long-Term Regional Transmission Planning for purposes of cost allocation. Given our decision to not require transmission providers to explain the benefits that they are using in cost allocation for Long-Term Regional Transmission Facilities, we believe this proposal is moot.

1510. We acknowledge New Jersey Commission's concern that permissive state-negotiated cost allocation could result in free riders. However, we note that, even for cost allocation methods filed pursuant to a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed, the costs allocated in accordance with such methods must be, as noted above, at least roughly commensurate with estimated benefits consistent with legal precedent. On compliance with this final rule, the Commission will evaluate whether any cost allocation method agreed to pursuant to a State Agreement Process, or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to, and filed with the Commission, allocates the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with the estimated benefits. Further, we believe that New Jersey Commission's concern is reduced by our modification to the NOPR proposal to require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method that must be used where a State Agreement Process fails to result in agreement; to the extent Relevant State

Entities do not agree to a cost allocation method through the State Agreement Process, the transmission provider's ex ante Long-Term Regional Transmission Cost Allocation Method will apply.

1511. Given our modification to the NOPR proposal to not require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, we find moot APPA's request that regional flexibility should include allowing transmission providers to demonstrate on compliance that their existing benefits used for cost allocation of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.[3211]

1512. With respect to the comments of City of New Orleans Council, OMS, Louisiana Commission, and Michigan Commission arguing that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2,[3212] which states that "[c]ost allocation should be as granular and accurate as possible,"[3213] we note that the flexibility we provide as to the consideration of benefits in cost allocation does not

[3211] APPA Initial Comments at 46. We also discuss related concerns in the Cost Allocation for Long-Term Transmission Facilities section, above.

[3212] City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35-36; Michigan Commission Initial Comments at 9; OMS Initial Comments at 7-8, 14.

[3213] OMS Initial Comments at 7-8.

prevent transmission providers in a particular transmission planning region from adopting a more granular approach.

1513. With respect to Southern and Dominion's assertions that the Commission must ensure that costs are allocated in a manner that is at least roughly commensurate with benefits by conducting its evaluation of proposed cost allocation methods in a particular manner,[3214] we reiterate that we will apply existing Commission and judicial precedent, including that cited by Dominion and Southern, in our evaluation of any proposed cost allocation methods for Long-Term Regional Transmission Facilities. With respect to Louisiana Commission's assertion that the cost allocation process should be allowed to consider allocations to all cost causers and beneficiaries, including generators,[3215] we continue to adhere to the flexibility we provided in Order No. 1000-A. In that order, we found that:

> With respect to generators being identified as beneficiaries and ultimately responsible for costs, . . . just as each transmission planning region retains the flexibility to define benefit and beneficiary, the public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to generators as beneficiaries that could be subject to regional or interregional cost allocation. However, . . . any effort to do so must not be inconsistent with the generator interconnection process under Order No. 2003 because, as [the Commission] stated in Order No. 1000, the generator interconnection process and

[3214] Southern Initial Comments at 29-30 (citing *ICC v. FERC I*, 576 F.3d at 476-77; *ICC v. FERC II*, 721 F.3d at 777; *ICC v. FERC III*, 756 F.3d at 564-565); Dominion Initial Comments at 43-44 (citing *ICC v. FERC I*, 576 F.3d at 477).

[3215] Louisiana Commission Initial Comments at 32.

> interconnection cost recovery are outside the scope of this rulemaking.[3216]

1514. We find Pacific Northwest Utilities' assertion that costs allocated to transmission providers in non-RTO/ISO transmission planning regions, like NorthernGrid, must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities,[3217] to be misplaced, as nothing in this final rule requires that only transmission providers in non-RTO/ISO transmission planning regions bear the ultimate responsibility for the costs of Long-Term Regional Transmission Facilities. We recognize that, in the absence of a single regional transmission provider who can recover the costs of Long-Term Regional Transmission Facilities on behalf of its transmission-owning members from all of its transmission customers in its transmission planning region, transmission providers in non-RTO/ISO regions require alternative arrangements to allocate and recover the costs of Long-Term Regional Transmission Facilities from the transmission customers that benefit from them. We expect that in non-RTO/ISO transmission planning regions, as is the case with Order No. 1000 regional transmission planning and cost allocation processes today,[3218] transmission providers will

[3216] Order No. 1000-A, 139 FERC ¶ 61,132 at P 680. While interconnection customers may voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, this process is distinct from allocating costs to generators under the Long-Term Regional Transmission Cost Allocation Method, as the Louisiana Commission appears to contemplate.

[3217] Pacific Northwest Utilities Initial Comments at 9-10.

[3218] *See e.g.*, *Duke Energy Carolinas, LLC*, 147 FERC ¶ 61,241 at P 453; *Pub.*

establish arrangements to implement the cost allocation methods for Long-Term Regional Facilities and recover the costs of such facilities from the transmission customers that benefit from them.

1515. Some commenters advocate for accounting for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities.[3219] Although we are not requiring transmission providers to account for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities, we are also not foreclosing the possibility that transmission providers and stakeholders may seek to account for certain public policy benefits when developing Long-Term Regional Transmission Cost Allocation Methods. We believe that states are well-positioned to value the benefits of achieving their respective public policy goals, consistent with past precedent in which we have affirmed the use of public policy benefits in regional transmission planning cost allocation,[3220] and they or other stakeholders can similarly do

*Serv. Co. of Colo*., 142 FERC ¶ 61,206 at P 314.

[3219] *See e.g.*, California Energy Commission Initial Comments at 3 (recommending that equity and environmental justice benefits be accounted for in cost allocation, including economic, health, and social benefits to disadvantaged communities); WE ACT Initial Comments at 5 (recommending the following benefits be accounted for in cost allocation: pollution reduction, health, jobs, and local economic development).

[3220] As noted in the Evaluation of the Benefits of Regional Transmission Facilities section, RTOs/ISOs that have used some form of public policy benefit in regional transmission planning include PJM and NYISO. Although explicitly *not* part of PJM's Order No. 1000 regional transmission planning, PJM uses a State Agreement Approach to allow the development of public policy projects. *See PPL Elec. Utils. Corp*., 181 FERC ¶ 61,178 at P 33 (finding that "allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects"). NYISO provides

so through engagement with transmission providers in their efforts to develop Long-Term Regional Transmission Cost Allocation Methods. In addition, to the extent states believe that a particular Long-Term Regional Transmission Facility would help achieve their public policy goals, we note our adoption in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final rule of opportunities for Relevant State Entities to voluntarily fund a portion of the cost of a Long-Term Regional Transmission Facility so that the facility can qualify for selection.[3221] The rule, consistent with the cost causation principle, does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities.[3222]

for cost allocations developed by the New York State Public Service Commission for transmission projects developed to meet public policy needs. *See Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106 at P 50 (finding that a volumetric load-ratio share cost allocation for certain local transmission upgrades was appropriate because the projects "benefit customers throughout the state insofar as they facilitate compliance with the New York State climate and renewable energy goals as required by New York State law and have been determined by the NYPSC to be necessary to meet such obligation").

[3221] *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[3222] *See Coal. of MISO Transmission Customers v. FERC*, 45 F.4th 1004, 1009 (D.C. Cir. 2022) ("The cost-causation principle requires that 'the cost of transmission facilities be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.'") (cleaned up) (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 53); *ICC v. FERC I*, 576 F.3d at 477.

### D. Miscellaneous Cost Allocation Comments and Proposals

#### 1. Comments

1516. Some commenters discuss the appropriate time frame for cost allocation for Long-Term Regional Transmission Facilities. Dominion states that costs should not be allocated until closer in time to when a transmission project will be built and beneficiaries identified rather than when the Long-Term Regional Transmission Facilities are identified.[3223] Ohio Consumers state that cost allocation decisions must be made on the basis of current or near-term transmission needs, and the Commission should not require subsidization for transmission lines on the theory that the line may be needed to serve future generation.[3224] OMS supports a requirement that transmission providers identify beneficiaries of transmission projects before any costs are allocated.[3225]

1517. Acadia Center and CLF state that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes.[3226]

1518. Some commenters stress the importance of cost containment oversight by the Commission. Joint Commenters support a cost management framework overseen by the Commission ensuring that the costs and benefits on which transmission projects are

[3223] Dominion Initial Comments at 42.

[3224] Ohio Consumers Initial Comments at 19.

[3225] OMS Initial Comments at 9.

[3226] Acadia Center and CLF Initial Comments at 17.

initially approved for cost allocation remain within initially contemplated parameters.[3227] State Water Contractors assert that the need for cost containment is acute for consumers in California, asserting that the CAISO high voltage transmission access charge has increased nearly 136% over the last decade. State Water Contractors argue that as increases in transmission costs have a direct impact on the cost of water delivery and treatment and given that water and energy are particularly intertwined in California, cost containment and regional flexibility are essential components to the justness and reasonableness of any final rule.[3228]

1519. Ohio Consumers state that the Commission should require that the transmission providers implementing any Long-Term Regional Transmission Planning requirements give appropriate consideration to public grants and other external sources of funding in any cost allocation processes, adding that transmission providers should first seek public grants prior to charging customers, because infrastructure funds must be accounted for, or else they would distort cost allocation processes.[3229]

1520. NextEra renews its request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of state right-of-first-refusal rights and require

[3227] Joint Commenters Reply Comments at 1.

[3228] State Water Contractors Reply Comments at 2-3.

[3229] Ohio Consumers Reply Comments at 15 (citing Infrastructure Investment and Jobs Act of 2021, Pub. L. No. 117-58, 135 Stat 429).

the direct assignment of such costs to customers in the incumbent transmission owner's zone.[3230]

### 2. Commission Determination

1521. We decline to adopt a particular time frame for determining the cost allocation for a Long-Term Regional Transmission Facility, as requested by Dominion, Ohio Consumers, and OMS. We believe that imposing a standardized time frame to determine cost allocation is unnecessary and could impede the regional flexibility that we provide to transmission providers under this final rule. However, as discussed above in the Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Regional Cost Allocation Principles section, if only a Long-Term Regional Transmission Cost Allocation Method is available for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), the determination of the applicable cost allocation must occur by or before its selection.

1522. We find Acadia Center and CLF's assertion that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes to be outside the scope of this proceeding, as is NextEra's request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of a state right of first refusal and require the direct assignment of such costs to customers in the incumbent transmission owner's zone.

[3230] NextEra Reply Comments at 26.

These suggestions are beyond the scope of the Commission's NOPR proposals and we believe that the record in this proceeding is insufficient to proceed with them.

1523. We also find outside the scope of this proceeding various commenters' statements regarding cost containment. We note that the Commission is examining issues related to transmission planning and cost containment in other proceedings.[3231]

## VII. Construction Work in Progress Incentive

### A. NOPR Proposal

1524. In the NOPR, the Commission proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of Construction Work In Progress (CWIP) costs in rate base (CWIP Incentive) for Long-Term Regional Transmission Facilities.[3232] The Commission noted that transmission providers may still accrue carrying costs incurred during the pre-construction or construction phase as Allowance for Funds Used During Construction (AFUDC) and only recover those costs from customers after the project is in service, in accordance with generally accepted utility

[3231] *See, e.g.*, Supplemental Notice of Technical Conference, Transmission Planning and Cost Management, Docket No. AD22-8-000 (Oct. 4, 2022).

[3232] NOPR, 179 FERC ¶ 61,028 at PP 328-329 n.522-523, 525-527 (citing Order No. 679, 71 FR 43294 (July 31, 2006), 116 FERC ¶ 61,057 at PP 9, 116-117, n.70). The Commission stated that the Commission has also provided that any public utility engaged in the sale of electric power for resale can file to include in rate base up to 50% of CWIP, subject to limitations. *Construction Work in Progress for Pub. Utils.; Inclusion of Costs in Rate Base*, Order No. 298, 48 FR 24323 (June 1, 1983), FERC Stats. & Regs. ¶ 30,455 (1983) (cross-referenced at 23 FERC ¶ 61,224), *order on reh'g*, 25 FERC ¶ 61,023 (1983). NOPR, 179 FERC ¶ 61,028 at P 329 n.524.

accounting principles for AFUDC.[3233] The Commission explained that this proposal would not affect Commission policy and regulations established before Order No. 679.[3234]

### B. Comments

#### 1. Interest in the NOPR Proposal

1525. Many commenters support the Commission's NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive and generally support permitting cost recovery instead through AFUDC, agreeing that extending the CWIP Incentive to Long-Term Regional Transmission Facilities would expose ratepayers to risks and cost burdens by requiring them to pay for Long-Term Regional Transmission Facilities that receive the incentive prior to those facilities being placed into service.[3235]

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[3233] NOPR, 179 FERC ¶ 61,028 at P 333.

[3234] *Id.* P 333 n.530. The Commission stated:

> [P]ublic utility transmission providers would still be allowed to request 50% CWIP in rate base, as is permitted pursuant to 18 CFR 35.25(c)(3), subject to an FPA section 205 filing detailing how the request meets the requirements of Order No. 298. We believe that the ability to include 50% CWIP in rate base, if requested and granted, reflects a more reasonable sharing of risks and benefits than the CWIP Incentive for Long-Term Regional Transmission Facilities given the greater uncertainty inherent in Long-Term Regional Transmission Planning, as proposed in this NOPR.

[3235] American Municipal Power Initial Comments at 34; APPA Initial Comments at 6, 46-47; California Commission Initial Comments at 58; California Water Initial Comments at 19-20; Clean Energy Buyers Initial Comments at 30-31; ELCON Initial

1526. California Commission and New England Systems argue that there is no evidence that any of the incentives established under FPA section 219, including the CWIP Incentive, have spurred investment in transmission infrastructure.[3236] California Commission argues that there was a great need to develop new transmission to bolster reliability and alleviate congestion when the CWIP Incentive was first introduced in Order No. 679, but that the prior decline in transmission investment has since been reversed.[3237] Further, California Commission argues that an inability to receive the CWIP Incentive would not present a barrier to entry for transmission development,[3238] stating that disallowing the CWIP Incentive for Long-Term Regional Transmission

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Comments at 19; Industrial Customers Initial Comments at 24-26; Joint Consumer Advocates Initial Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4; Large Public Power Initial Comments at 41-42; Louisiana Commission Initial Comments at 36; Massachusetts Attorney General Initial Comments at 23; NARUC Initial Comments at 54-55; NASUCA Initial Comments at 8-9; NESCOE Initial Comments at 73; Nevada Commission Initial Comments at 14; North Carolina Commission and Staff Initial Comments at 17-18; NRG Initial Comments at 21-22; Ohio Commission Federal Advocate Initial Comments at 15-16; Ohio Consumers Initial Comments at 29; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; Resale Iowa Initial Comments at 2, 12-13; Six Cities Initial Comments at 11; State Agencies Initial Comments at 24; TAPS Initial Comments at 5, 27-29; Transmission Dependent Utilities Initial Comments at 2-4; Virginia Attorney General Initial Comments at 4-6.

[3236] California Commission Reply Comments at 11-12; New England Systems Reply Comments at 15-16.

[3237] California Commission Reply Comments at 8-10 (citing US DOE, *National Electric Transmission Congestion Study*, at 21(Sept. 2020), https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf).

[3238] *Id.* at 19-20 (citing CAISO Initial Comments at 44).

Facilities would affect incumbent and nonincumbent transmission developers equally, and that developers could continue to seek the CWIP Incentive for economic and reliability transmission projects.[3239] Louisiana Commission states that if an independent transmission developer or utility has won a competitive bidding process to construct transmission facilities, that entity should have the financial wherewithal to finance the project without a loan from ratepayers.[3240]

1527. Several commenters assert that the CWIP Incentive shifts risks to customers.[3241] Pennsylvania Commission, Large Public Power, and Resale Iowa argue that allowing the CWIP Incentive could substantially increase the risk of customers paying for transmission facilities that are never built and from which they derive no benefit, leading to rates that are unjust and unreasonable.[3242] NARUC, New England Systems, and Virginia Attorney General agree with the proposed reform because it better aligns risk

[3239] *Id*.

[3240] Louisiana Commission Initial Comments at 36.

[3241] California Commission Reply Comments at 14; Large Public Power Initial Comments at 41; Louisiana Commission Initial Comments at 36; NARUC Initial Comments at 55-56; New England Systems Reply Comments at 15; Ohio Commission Federal Advocate Initial Comments at 16; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12-13; Virginia Attorney General Reply Comments at 2.

[3242] Large Public Power Initial Comments at 41; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12-13.

and reward between shareholders and customers with respect to Long-Term Regional Transmission Facilities.[3243]

1528. Several other commenters state that the longer the transmission planning horizon, the higher the risk that resulting transmission facilities will not be needed, which may result in stranded costs.[3244] For this reason, Industrial Customers state that shifting risks from transmission developers to customers is particularly problematic for Long-Term Regional Transmission Facilities.[3245] Dominion states that it does not take a position on the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, but nevertheless asserts that shifting the risk for long-term transmission projects to transmission providers will help ensure that only those long-term projects that are "confidently needed" will be developed. However, for states that may allow or require the inclusion of the CWIP Incentive in rate base, Dominion states that the Commission should allow for deference to the state cost recovery structure.[3246]

[3243] NARUC Initial Comments at 55-56; New England Systems Reply Comments at 15 (citing NARUC Initial Comments at 56); Virginia Attorney General Reply Comments at 2 (citing NARUC Initial Comments at 55).

[3244] Clean Energy Buyers Reply Comments at 10-11; Dominion Initial Comments at 53-54; Industrial Customers Reply Comments at 9; Transmission Dependent Utilities Reply Comments at 4; Virginia Attorney General Reply Comments at 3.

[3245] Industrial Customers Reply Comments at 9.

[3246] Dominion Initial Comments at 53.

1529. Several commenters suggest that such reform may mitigate certain risks of the transmission provider over-building the system.[3247] For example, Massachusetts Attorney General and North Dakota Commission state that the Commission's proposed limit on the CWIP Incentive would provide ratepayers greater protection from financing inefficient or over-built regional transmission projects.[3248] New England Systems argue that entities in favor of continuing the CWIP Incentive gain financially from the incentive.[3249] Industrial Customers state that the alleged benefits of the CWIP Incentive to customers are tenuous at best.[3250]

1530. Multiple commenters suggest that prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive may improve the planning and building of new transmission facilities.[3251] New England Systems, PJM States, and North Carolina Commission and Staff assert that removing the CWIP Incentive will

[3247] Massachusetts Attorney General Initial Comments at 24-25; North Carolina Commission and Staff Initial Comments at 18; North Dakota Commission Initial Comments at 6; Pennsylvania Commission Initial Comments at 17-18; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

[3248] Massachusetts Attorney General Initial Comments at 24-25; North Dakota Commission Initial Comments at 6.

[3249] New England Systems Reply Comments at 15-16 (citing Avangrid Initial Comments at 26).

[3250] Industrial Customers Reply Comments at 9-10.

[3251] North Carolina Commission and Staff Initial Comments at 18; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

appropriately reduce incentives to over-build transmission, which could lead to rates being unjust and unreasonable.[3252] Similarly, US Climate Alliance supports prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, as doing so would align incentives for transmission providers to deliver transmission projects on time and within budget.[3253]

1531. California Commission argues that money paid earlier as CWIP is more valuable than money paid later and that comparisons of savings under the CWIP Incentive and under AFUDC are only meaningful if an interest adjustment is made to account for the time in which payments are made.[3254] Industrial Customers explain that, to customers, the difference between the AFUDC and CWIP approaches is primarily the time value of money.[3255] Kentucky Commission Chair Chandler, NASUCA, and California Commission express concern that today's ratepayers are forced to pay for tomorrow's transmission projects, which they refer to as intergenerational inequity, and they are especially concerned if a project will not provide service until a much later date.[3256]

[3252] New England Systems Reply Comments at 14-15; North Carolina Commission and Staff Initial Comments at 18; PJM States Initial Comments at 13.

[3253] US Climate Alliance Initial Comments at 2.

[3254] California Commission Reply Comments at 13.

[3255] Industrial Customers Reply Comments at 9.

[3256] Kentucky Commission Chair Chandler Initial Comments at 8; NASUCA Initial Comments at 9; California Commission Reply Comments at 17 (citing NASUCA Initial Comments at 9).

### 2. Concerns with the NOPR Proposal

1532. Many commenters oppose the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive.[3257] Several commenters cite the Commission's findings in Order No. 679 explaining that the CWIP Incentive can help remove a disincentive to construct new transmission infrastructure, which can involve very long lead times and considerable risk to the utility that the project may not go forward.[3258] National Grid and Avangrid, for example, argue that Long-Term Regional Transmission Facilities will likely have very long lead times and place even greater risk on transmission providers relative to transmission facilities planned and

[3257] AEP Initial Comments at 38-40; Ameren Initial Comments at 48-51; Avangrid Initial Comments at 24-28; CAISO Initial Comments at 43-45; Consumer Organizations Initial Comments at 7-10; Duke Initial Comments at 44-45; Duquesne Light Initial Comments at 2-6; EEI Initial Comments at 42-45; EEI Reply Comments at 17-18; Entergy Initial Comments at 35-37; Eversource Initial Comments at 31-35; Eversource Reply Comments at 2; Harvard ELI Initial Comments at 7-10; Indicated PJM TOs Initial Comments at 26-28; MISO TOs Initial Comments at 65-66; National Grid Initial Comments at 27-30; New York TOs Initial Comments at 23-24; New York Transco Initial Comments at 13-16; Pattern Energy Initial Comments at 34-36; PG&E Initial Comments at 18-20; PPL Initial Comments at 29-30; SoCal Edison Initial Comments at 13-14; Transource Initial Comments at 3; WIRES Initial Comments at 17-19.

[3258] Ameren Initial Comments at 49; EEI Initial Comments at 42-43; EEI Reply Comments at 17-18; Eversource Reply Comments at 2; MISO TOs Initial Comments at 66; National Grid Initial Comments at 28-29; WIRES Initial Comments at 17-18 (all citing Order No. 679, 116 FERC ¶ 61,057 at P 115).

developed on a more typical timeframe.[3259] Similarly, WIRES argues that the rationale underlying the CWIP Incentive remains valid today.[3260]

1533. Some commenters also cite the Commission's 2012 Transmission Incentive Policy Statement as support for the CWIP Incentive as a risk-reducing mechanism to transmission providers, which these commenters state can increase credit ratings and lower capital costs.[3261] In addition, several commenters reference Commission findings in numerous prior incentive proceedings where the Commission has affirmed the benefits that the CWIP Incentive provides to customers and transmission providers, attesting that the NOPR proposal is in direct opposition to such findings.[3262]

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[3259] Avangrid Reply Comments at 6-7; National Grid Initial Comments at 28-29.

[3260] WIRES Initial Comments at 17-18.

[3261] Ameren Initial Comments at 49; EEI Initial Comments at 42; Eversource Initial Comments at 32 (all citing *Promoting Transmission Investment Through Pricing Reform*, Policy Statement, 141 FERC ¶ 61,129, at P 12 (2012)).

[3262] AEP Initial Comments at 38 (citing *Ne. Utils. Serv. Co. & Nat'l Grid USA*, 125 FERC ¶ 61,183, at P 89 (2008)); Ameren Initial Comments at 49 (citing *United Illuminating*, 119 FERC ¶ 61,182, at P 63 (2007)); Duquesne Light Initial Comments at 3 (citing *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284, at P 58 (2007); *Am. Elec. Power Service Corp.*, 116 FERC ¶ 61,059, at P 3 (2006)); EEI Initial Comments at 44 (citing *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at PP 42-43 (2008), *reh'g denied*, 124 FERC ¶ 61,229 (2008)); National Grid Initial Comments at 29 (citing *Tucson Elec. Power Co.*, 174 FERC ¶ 61,223, at P 25 (2021); *S. Cal. Edison Co.*, 172 FERC ¶ 61,241, at P 31 (2020); *United Illuminating Co.*, 167 FERC ¶ 61,126, at P 36 (2019)); MISO TOs Initial Comments at 66-67 (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229, at P 78 (2011); *Duquesne Light Co.*, 166 FERC ¶ 61,074, at P 32 (2019); *United Illuminating, Co.*, 167 FERC ¶ 61,126 at P 36; *GridLiance W. Transco LLC*, 164 FERC ¶ 61,049, at P 25 (2018); *NextEra Energy Transmission N.Y., Inc.*, 162 FERC ¶ 61,196, at P 64 (2018); *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,089, at P 33 (2017); *Duquesne Light Co.*, 179 FERC ¶ 61,218, at P 17 (2022)); New York TOs Initial Comments at 23 (citing *Okla. Gas & Elec. Co.*, 133 FERC ¶ 61,274, at P 48 (2010); *Pepco Holdings, Inc.*, 125 FERC ¶

1534. Some commenters assert that the NOPR proposal runs counter to obligations established in the Energy Policy Act of 2005 and FPA section 219 to facilitate capital investment in transmission infrastructure and would likely impede the development of regional transmission facilities identified to meet changes in the resource mix and demand.[3263]

1535. Numerous commenters argue that the proposal runs counter to the objectives of the NOPR that seek to encourage the development and completion of regional transmission facilities needed to address changes in the resource mix or demand over a longer time horizon.[3264] For example, CAISO, MISO TOs, and Avangrid suggest that it is counterintuitive for the Commission to acknowledge a lack of regional transmission facilities in the NOPR, yet propose to undo the most reasonable tool that aids cash flow and reduces uncertainty associated with building those facilities.[3265] Certain commenters

61,130, at P 63 (2008)).

[3263] Ameren Initial Comments at 48; CAISO Initial Comments at 43-44; EEI Initial Comments at 42-43; Indicated PJM TOs Initial Comments at 26-28; MISO TOs Initial Comments at 71-72; National Grid Initial Comments at 28; PPL Initial Comments at 29-30; WIRES Initial Comments at 17-18.

[3264] AEP Initial Comments at 39; Ameren Initial Comments at 50-51; Avangrid Initial Comments at 25; Avangrid Reply Comments at 6-8; Eversource Initial Comments at 2, 31-32; MISO TOs Initial Comments at 70-76; Pattern Energy Initial Comments at 35-36; PG&E Initial Comments at 18-19.

[3265] Avangrid Reply Comments at 7 (citing CAISO Initial Comments at 45; MISO TOs Initial Comments at 71-72, 74-75); CAISO Initial Comments at 45; MISO TOs Initial Comments at 74-76 (citing NOPR, 179 FERC ¶ 61,028 at PP 1, 9, 25, 35, 47, 330-331).

state that the CWIP Incentive assists with getting needed transmission projects built.[3266] AEP and Avangrid state that the CWIP Incentive is particularly well-suited to incentivizing the type of large, regional transmission projects that the Commission hopes to increase through the NOPR, which often present higher costs, longer lead times, an increase in possible rate shock, and present cash flow difficulties.[3267]

1536. Several commenters point to cash flow benefits enabled through the CWIP Incentive and associated benefits to customers.[3268] For example, New York TOs and PG&E contend that the cash flow benefits from the CWIP Incentive allow a utility to reduce the need for external financing and instead allocate capital to other projects that benefit additional ratepayers.[3269]

1537. Several commenters contend that the Commission has failed to adequately justify the NOPR proposal, asserting that the rationale is weak or arguing that the Commission has not shown that its existing policy is unjust and unreasonable.[3270] MISO TOs argue

[3266] AEP Initial Comments at 39; Ameren Initial Comments at 50; Avangrid Initial Comments at 26; MISO TOs Initial Comments at 69.

[3267] AEP Initial Comments at 39; Avangrid Reply Comments at 10.

[3268] AEP Initial Comments at 38-39; Ameren Initial Comments at 49; Avangrid Initial Comments at 25; EEI Initial Comments at 44-45; EEI Reply Comments at 17; Entergy Initial Comments at 37; Eversource Initial Comments at 31; Indicated PJM TOs Initial Comments at 26-28; MISO TOs Initial Comments at 66-67, 71, 74-76; National Grid Initial Comments at 28-29; New York TOs Initial Comments at 23-24; New York Transco Initial Comments at 13; Pattern Energy Initial Comments at 35; PG&E Initial Comments at 19; Transource Initial Comments at 3; WIRES Initial Comments at 17-18.

[3269] New York TOs Initial Comments at 23-24; PG&E Initial Comments at 19.

[3270] Ameren Initial Comments at 50-51; Duke Initial Comments at 44-45;

that the Commission's claim that ratepayers do not receive benefits from the regional transmission facilities during the construction period is unsupported by precedent or analysis and is contrary to longstanding Commission policy. Further, they observe that a transmission facility cannot be developed and placed into service overnight, so artificially dividing up the customer benefits to pre-operation and post-operation ignores the realities of transmission development.[3271] Where the proposal identified that additional ratepayer protections may be necessary to balance customers' interest in just and reasonable rates against investors' interest in earning a return on invested capital or mitigating against over-investment in regional transmission facilities, MISO TOs reiterate that the CWIP Incentive's benefits promote just and reasonable rates by providing incentives encouraging transmission construction consistent with the Commission's FPA mandate and assert that an investor's rate of return is set in unrelated proceedings.[3272]

1538. Pattern Energy states that the Commission has provided no policy justification or factual basis to distinguish the risk incurred during the planning phase from other risk

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Duquesne Light Initial Comments at 2-3; EEI Initial Comments at 44-45; Eversource Initial Comments at 33-34; MISO TOs Initial Comments at 66-67 (citing NOPR, 179 FERC ¶ 61,028 at P 331); Pattern Energy Initial Comments at 35.

[3271] MISO TOs Initial Comments at 69 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

[3272] *Id.* at 72-73 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

factors, such as size, scope, or cost, which it asserts is a departure from the Order No. 679 policy on the CWIP Incentive.[3273]

1539. Many commenters also argue that, while the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive is intended to mitigate shifting too much risk to customers, the proposal ignores many of the benefits that the current CWIP Incentive policy providers to customers.[3274] EEI argues that commenters that support the proposal also fail to recognize these benefits and the important role that this incentive serves in facilitating new transmission investment.[3275] Many commenters that oppose the NOPR proposal tout such benefits, such as improved cash flow and the ability for transmission providers to secure better financing through higher credit ratings, resulting in lower interest expense costs that benefit customers.[3276] Consumer Organizations and Eversource contend that carrying a

[3273] Pattern Energy Initial Comments at 35.

[3274] AEP Initial Comments at 38-39; Ameren Initial Comments at 48-51; Avangrid Initial Comments at 27-28; Duke Initial Comments at 45; Duquesne Light Initial Comments at 3-5; EEI Initial Comments at 44-45; EEI Reply Comments at 18; Eversource Initial Comments at 31-34; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66-76; National Grid Initial Comments at 29; New York TOs Initial Comments at 23-24; New York Transco Initial Comments at 13-14; PG&E Initial Comments at 19-20; SoCal Edison Initial Comments at 3, 13-14; WIRES Initial Comments at 18-19.

[3275] EEI Reply Comments at 18 (citing NASUCA Initial Comments at 8-9; Transmission Dependent Utilities Initial Comments at 2-4).

[3276] Ameren Initial Comments at 42, 50; Avangrid Initial Comments at 27; Duke Initial Comments at 45; Duquesne Light Initial Comments at 4-6; EEI Initial Comments at 44-45; MISO TOs Initial Comments at 66-67; PG&E Initial Comments at 19.

significant amount of debt in AFUDC rather than being recovered through the CWIP Incentive can result in lower credit ratings and higher capital costs, which are passed through to customers, and assert that "with AFUDC, consumers are likely to pay more in the long run."[3277]

1540. Some commenters state that the CWIP Incentive helps to avoid rate shock and provides other cost savings relative to AFUDC.[3278] Avangrid states that arguments about the sharing of risk between utilities and customers that the Commission used to support the NOPR proposal fail to consider the budgeting risk to customers under the AFUDC approach, and claims that these arguments ignore the benefit of price stability.[3279]

1541. Several commenters state that the Commission can take more targeted action to address concerns of uncertainty in Long-Term Regional Transmission Planning rather than prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, for instance, by ensuring sufficiently robust selection criteria, project

[3277] Consumer Organizations Initial Comments at 7-8; Eversource Reply Comments at 4 (quoting Consumer Organizations Initial Comments at 7).

[3278] AEP Initial Comments at 38-39; Ameren Initial Comments at 50; Avangrid Initial Comments at 27-28; Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4-9); Consumer Organizations Initial Comments at 7-10; Duquesne Light Initial Comments at 4; EEI Initial Comments at 44; EEI Reply Comments at 17-18; Eversource Initial Comments at 31-32; Eversource Reply Comments at 4-5; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66-76; National Grid Initial Comments at 28-29; New York TOs Initial Comments at 23-24; PG&E Initial Comments at 19; PG&E Reply Comments at 13-14; SoCal Edison Initial Comments at 13-14; WIRES Initial Comments at 19.

[3279] Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4-9).

review, and approval processes.[3280] CAISO contends that these measures are more appropriate ways to account for the root cause of the risk of over-building and to ensure that customers are protected from the costs of transmission facilities that may be less certain.[3281] R Street states that the NOPR's proposal to remove the CWIP Incentive by itself will not thwart increasing transmission costs, and the Commission must recognize preserving and expanding competition as a way to contain costs.[3282]

1542. Eversource and New York Transco assert that case-by-case evaluation for any request for transmission incentives, including the CWIP Incentive, affords interested parties the opportunity to intervene and provide comments, culminating in a Commission determination of whether the incentive is just and reasonable, thereby protecting customer interests.[3283]

1543. Eversource, Harvard ELI, and National Grid state that it would be best to make changes in incentives policy in a comprehensive transmission incentives rulemaking instead of in this final rule.[3284] Eversource and National Grid argue that, at a minimum,

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[3280] Avangrid Reply Comments at 8 (citing CAISO Initial Comments at 45); CAISO Initial Comments at 45; EEI Reply Comments at 18; PG&E Reply Comments at 13-14.

[3281] CAISO Initial Comments at 6-7, 45.

[3282] R Street Reply Comments at 2.

[3283] Eversource Reply Comments at 4-5; New York Transco Reply Comments at 7-8.

[3284] Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4-5, 7-8, 10; National Grid Initial Comments at 27.

the Commission should defer a decision on the CWIP Incentive to the rulemaking proceeding on transmission incentives in Docket No. RM20-10-000, where the Commission has already established a full and complete record.[3285] Harvard ELI suggests that any action on the CWIP Incentive be deferred to another proceeding to develop a holistic package of incentives, penalties, and oversight mechanisms after the Commission has established the full goals and procedural rules for Long-Term Regional Transmission Planning.[3286]

1544. Certain commenters raise concerns of unintended consequences of the proposal. CAISO and Transource state that new transmission developers may be disadvantaged if the Commission prohibits Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive.[3287] Specifically, CAISO notes that the Commission approved a provision in its OATT that permits a nonincumbent transmission developer within CAISO to recover Commission-authorized transmission revenue requirements associated with transmission projects under construction before the facilities are turned over to CAISO operational control, which CAISO contends is a way that it addresses barriers to transmission development by nonincumbent transmission developers.[3288]

[3285] Eversource Initial Comments at 33; National Grid Initial Comments at 27.

[3286] Harvard ELI Initial Comments at 4-5, 7-8, 10.

[3287] CAISO Initial Comments at 43-45; Transource Initial Comments at 3.

[3288] CAISO Initial Comments at 43-44 (citing *Cal. Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,237 (2014)).

CAISO contends that the Commission should not preclude transmission developers from using the CWIP Incentive for Long-Term Regional Transmission Facilities, especially because the Commission would continue to allow the CWIP Incentive for reliability and economic transmission projects.[3289]

### 3. Interaction of the CWIP Incentive with the Abandoned Plant Incentive

1545. Many commenters raise concerns with the interaction between the CWIP Incentive and the transmission incentive that allows applicants to request 100% of prudently-incurred costs associated with abandoned transmission projects be included in transmission rates if such abandonment is outside the control of management (Abandoned Plant Incentive).[3290] APPA, California Commission, Industrial Customers, NARUC, and Virginia Attorney General suggest that unless and until the Commission reconsiders the Abandoned Plant Incentive, customers will continue to face risks associated with Long-Term Regional Transmission Facilities.[3291] Specifically, APPA states that the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive will not necessarily protect customers from the

[3289] *Id.* at 44-45.

[3290] Order No. 679, 116 FERC ¶ 61,057 at P 163.

[3291] APPA Initial Comments at 46-47; California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 24-27; Industrial Customers Reply Comments at 9; NARUC Initial Comments at 55; Virginia Attorney General Initial Comments at 6-7; Virginia Attorney General Reply Comments at 5-6.

costs of potentially unneeded facilities identified through Long-Term Regional Transmission Planning, given the Commission's policies on recovery of abandoned plant costs (including the Abandoned Plant Incentive under Order No. 679).[3292] Similarly, NARUC, Virginia Attorney General, and Industrial Customers request that the Commission review the current abandoned plant policy to ensure that customer benefits from the adoption of the NOPR proposal with respect to the CWIP Incentive do not disappear if those costs are still recovered from customers as abandoned plant.[3293]

1546. Industrial Customers suggest that, without additional reforms limiting the recovery of abandoned plant costs, customers will continue to face the possibility of paying for transmission that is never built.[3294] Further, Industrial Customers and California Commission state that AFUDC could be a superior approach for customers, but only in a final rule that adopts certain protections to ensure that customers do not pay for abandoned plant costs.[3295] Industrial Customers argue that the Commission should adopt

[3292] APPA Initial Comments at 46-47.

[3293] Industrial Customers Reply Comments at 10 (citing MISO States Initial Comments at 14; NARUC Initial Comments at 55); NARUC Initial Comments at 55; Virginia Attorney General Reply Comments at 5 (citing NARUC Initial Comments at 55).

[3294] Industrial Customers Initial Comments at 25-26.

[3295] California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 26-27.

customer safeguards for transmission projects that are abandoned, including a more thorough review of whether costs were prudently incurred prior to abandonment.[3296]

### C. Commission Determination

1547. We decline to act at this time to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities. We agree with commenters[3297] that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives after the Commission has finalized its Long-Term Regional Transmission Planning reforms. In particular, we conclude that whether the Commission's transmission incentives are appropriately "benefitting consumers by ensuring reliability and reducing the cost of delivered power"[3298] is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.

## VIII. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements

### A. NOPR Proposal

1548. In the NOPR, the Commission proposed to use the discretion afforded by FPA section 309 to amend Order No. 1000's findings and nonincumbent transmission

[3296] Industrial Customers Reply Comments at 9.

[3297] Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4-5, 7-8, 10; National Grid Initial Comments at 27.

[3298] 16 U.S.C. 824s(a).

developer reforms in part, so as to permit the exercise of federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.[3299] The Commission reasoned that given the investment trends observed since Order No. 1000's implementation, it is possible that the Commission's Order No. 1000 nonincumbent transmission developer reforms may be inadvertently discouraging investment in and development of regional transmission facilities to some extent.[3300] Specifically, the Commission posited that incumbent transmission providers, as a result of those reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint.[3301]

1549. The Commission preliminarily found that, while the *unconditional* exercise of federal rights of first refusal for entirely new selected transmission facilities remains unjust and unreasonable, Order No. 1000's remedy—requiring the elimination of *all* federal rights of first refusal for entirely new selected transmission facilities—was overly

[3299] *See* NOPR, 179 FERC ¶ 61,028 at P 351.

[3300] *Id.* P 350.

[3301] *Id*.

broad.[3302] The Commission further preliminarily found that, while Order No. 1000's reforms have a sound theoretical basis, the remedy prescribed by Order No. 1000 failed to recognize that some of the expected benefits from the competitive transmission development processes could be achieved or at least reasonably approximated through other means.[3303]

1550. Accordingly, the Commission proposed to allow transmission providers to propose, pursuant to FPA section 205, new federal rights of first refusal for incumbent transmission providers, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain requirements described in the NOPR.[3304] The Commission asserted that if the NOPR proposal was adopted, Order No. 1000's findings and mandates would be amended such that joint ownership conditions would presumptively be found to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by transmission providers, if imposed upon the exercise of an incumbent transmission provider's federal right of first refusal for selected transmission facilities.

1551. The Commission explained that an incumbent transmission provider could establish qualifying joint ownership with unaffiliated nonincumbent transmission

[3302] *Id.* PP 351-352, 354.

[3303] *Id.* P 353.

[3304] *Id.* P 354.

developers as defined in Order No. 1000, or another unaffiliated entity, including another incumbent transmission provider.[3305] However, the Commission also proposed that to qualify for the presumption, incumbent transmission providers with a conditional federal right of first refusal would not be allowed to structure joint-ownership arrangements such that unaffiliated entities were offered less than a meaningful level of participation and investment in the proposed regional transmission facility.[3306] The Commission further explained that an incumbent transmission provider's conditional federal right of first refusal should not significantly delay the regional transmission planning process or result in prolonged uncertainty regarding which transmission facilities will (or, alternatively, will not) be subject to competitive transmission development processes.[3307]

1552. The Commission noted that proposals for jointly owned regional transmission facilities would still need to be evaluated by transmission providers in the transmission planning region and would not be exempt from selection requirements. However, the Commission also explained that the evaluation process for such jointly owned regional transmission facility proposals would not involve running the region's competitive transmission development process.[3308]

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[3305] *Id.* P 365.

[3306] *Id.* P 371.

[3307] *Id.* P 366.

[3308] *Id.* P 370.

### B. Comments

#### 1. General Perspectives and Approach to Reform

1553. Commenters share a variety of perspectives on the track record of competitive transmission development processes, the wisdom of the nonincumbent transmission developer reforms adopted in Order No. 1000, and the steps they believe the Commission should take in response to the concerns identified in the NOPR. Several state entities, customer-affiliated groups, and nonincumbent transmission developers, such as LS Power, NextEra, and the US DOJ and FTC, defend competitive transmission development processes as beneficial and argue for their expansion.[3309] Some US Senators agree, arguing that allowing for a conditional federal right of first refusal would be anti-competitive, could hinder development of new transmission, and could cause excessive costs to consumers.[3310] On the other hand, representatives of incumbent

[3309] *See, e.g.*, American Municipal Power Reply Comments at 3-4; Anbaric Initial Comments at 4-5; California Commission Initial Comments at 100, 103-104; Competition Advocates Supplemental Comments at 1-3 & n.17 (citing Jennifer Chen & Devin Hartman, R Street Institute, *Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles* (May 2022), http://www.rstreet.org/research/transmission-reform-strategy-from-a-customer-perspective-optimizing-net-benefits-and-procedural-vehicles); Competition Coalition Initial Comments at 16-22, 68-70; LS Power Initial Comments at 38-39, 44; LS Power Partial Reply Comments at 20-23; LS Power and NRG Supplemental Comments at 38-39; NextEra Initial Comments at 18-19, 24-27, 29; Ohio Consumers Reply Comments at 16-18; Resale Iowa Reply Comments at 5-6; US DOJ and FTC Initial Comments at 7-8, 10-11, 13, 22.

[3310] US Senators Heinrich and Lee Supplemental Comments at 1-2. *See also* Freeport-McMoRan Supplemental Comments at 6 (asserting that the federal right of first refusal is anticompetitive and would enrich transmission owning utility shareholders).

transmission providers and others (e.g., EEI, WIRES, DATA, the MISO TOs) critique such processes and many call for the Commission to restore unconditional federal rights of first refusal.[3311] Each side of the debate offers consultant reports to substantiate their position, with pro-competition advocates relying on studies by the Brattle Group (Brattle) that present competitive transmission development processes in a largely favorable light,[3312] and advocates for federal rights of first refusal relying on contrasting studies by Concentric Energy Advisors (Concentric).[3313] In general, pro-competition advocates,

[3311] *See, e.g.*, DATA Initial Comments at 3-7 (detailing experiences by transmission planning regions and concluding that "competitive processes have become a distraction from, and an impediment to, the larger goal of expanding the transmission system to support current and future needs"); EEI Initial Comments at 24, 26, 27-31; EEI Supplemental Comments at 1-3 (citing Concentric Energy Advisors, *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits*, at 1 (Aug. 2022) (2022 Concentric Report); DATA Supplemental Comments at 4); MISO TOs Initial Comments at 53-56; National Grid Initial Comments at 4-5, 31 (doubting that Order No. 1000 competitive transmission development processes have broadly produced beneficial outcomes); PJM Initial Comments at 47-48 (enumerating the challenges faced in and resources required to complete competitive transmission development processes); Vermont Electric and Vermont Transco Initial Comments at 4-5 (referencing "a number of unintended consequences that have not benefited the regional grid"); WIRES Initial Comments at 14-15; WIRES Reply Comments at 4-8; Xcel Initial Comments at 5 ("[Right of first refusal] elimination was a policy experiment that did not bring about the desired result.").

[3312] In general, Brattle's analysis has found that competitive transmission development processes have yielded "cost savings averaging between 20% and 30%" once historical levels of cost escalation in transmission development were taken into account. *See* Brattle Apr. 2019 Competition Report at 39-43. US DOJ and FTC also contend that there are many instances in which competitive transmission development processes have benefitted consumers. *See* US DOJ & FTC Initial Comments at 13-16 (collecting examples); *but see* DATA Initial Comments at 7-9 (critiquing Brattle's analyses); WIRES Reply Comments at 5 (same).

[3313] In addition to citations to past Concentric reports, DATA attaches to its initial comments a 2022 Concentric report, which DATA characterizes as showing that

such as LS Power, contend that competitive transmission development processes are essential to just and reasonable rates, while representatives of incumbent transmission providers counter that just and reasonable transmission rates are separately and independently ensured by and through FPA section 205 rate proceedings.[3314]

1554. At a high level, pro-competition commenters express concern that the NOPR proposal could divert regional transmission facility development opportunities to incumbent transmission providers, opportunities that would otherwise be subject to competitive transmission development processes. For example, US DOJ and FTC argue

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competitive transmission development processes add significant time, delay customer benefits, and do not produce clear evidence of customer savings given cost cap exclusions and delays. DATA Initial Comments at 1-2, 7-11, 14-15; *id.* at attach. A (2022 Concentric Report). DATA also attaches to its comments a whitepaper that DATA alleges updates the Brattle Apr. 2019 Competition Report, and which DATA contends shows that Order No. 1000-mandated competition resulted in exceeding cost baselines by at least six percent. DATA Supplemental Comments at 3-4; *id*. at attach.: Whitepaper (DATA, *Revisiting the Evidence on Cost Savings from Transmission Competition* (Dec. 2023) (2023 DATA Whitepaper)). *But see* Massachusetts Attorney General Reply Comments at 8-9 (critiquing the 2022 Concentric Report); NextEra Reply Comments at 3, 7-17 (same); *see also* Competition Coalition Supplemental Comments at 2-7 (arguing that, in addition to DATA lacking good cause and failing to file a motion to lodge new evidence, the 2023 DATA Whitepaper fails to, among other things, demonstrate that cost-of-service regulation is as effective as competition in establishing just and reasonable transmission rates).

[3314] *Compare* LS Power Initial Comments at 32-37, *with* Ameren Initial Comments at 36-37, and DATA Initial Comments at 13-14, and MISO TOs Initial Comments at 60-61. Several commenters argue at length about the NOPR proposal's invocation of FPA sections 309 and 206 as legal authority and explore various alternatives. *See, e.g.*, Ameren Initial Comments at 38-39; California Commission Initial Comments at 101-103; DATA Initial Comments at 17-18 & n.43; Eversource Initial Comments at 39-42; Indicated PJM TOs Initial Comments at 34-35; ITC Initial Comments at 36; LS Power Initial Comments at 14, 19-20, 24, 57-61; MISO TOs Initial Comments at 50-53; NextEra Initial Comments at 51-53.

that relying on federal rights of first refusal to address the problems the Commission has identified would eliminate or distort the benefits of competitive transmission development processes, which generally "make transmission development less costly, more resilient, and more innovative."[3315] NESCOE "implores the Commission to maintain flexibility that enables ISO-NE to issue competitive solicitations to identify projects in furtherance of state laws."[3316] Some pro-competition commenters believe that states and state commissions are best positioned to determine whether competition between nonincumbent transmission developers and incumbent transmission providers is beneficial.[3317]

1555. Meanwhile, commenters that generally support federal rights of first refusal express skepticism that the NOPR proposal would be sufficient to address the identified problems, or offer only qualified support for the NOPR proposal as an inferior alternative to the Commission fully restoring unconditional federal rights of first refusal.[3318] In

[3315] *See* US DOJ & FTC Initial Comments at 22.

[3316] NESCOE Supplemental Comments at 6-7.

[3317] *E.g.*, California Commission Initial Comments at 104-105; Harvard ELI Initial Comments at 5-6, 31-33; *see also* Minnesota State Entities Initial Comments at 9; Mississippi Commission Reply Comments at 8 & n.31; New Jersey Commission Initial Comments at 37; PIOs Initial Comments at 85; PJM States Initial Comments at 13-14. *But see* NextEra Reply Comments at 23-25 (questioning whether allowing states to dictate the terms of a filed rate would be legally sound); PJM Reply Comments at 25-29 (raising potential legal ambiguities and practical issues).

[3318] *E.g.*, Avangrid Initial Comments at 18-24; DATA Initial Comments at 20-22; Eversource Initial Comments at 35-36, 42-45; Indicated PJM TOs Reply Comments at 2, 13-14; ITC Initial Comments at 32-43; Xcel Initial Comments at 5.

addition, if adopted, several incumbent transmission providers advocate for requiring transmission providers to implement the NOPR proposal instead of permitting them to decide whether to implement it.[3319]

1556. While commenters offer numerous variations on these high-level opposing views, several commenters argue that there are problems with the basic structure of competitive transmission development processes and express concerns that generally align with those expressed by the Commission in the NOPR. For example, while not agreeing with the NOPR proposal, ELCON expresses concern that "current competition regimes have led eligible developers to retreat to their various corners, which reduces transparency, information sharing, and open dialogue in the planning process[,]" and contends that both incumbent transmission owners and nonincumbent transmission developers have adopted a zero-sum posture to transmission planning that leads to a patchwork of planning and lack of innovation.[3320] Similarly, WIRES, citing a report by Grid Strategies, suggests that

[3319] *See, e.g.*, DATA Initial Comments at 19-21; Exelon Initial Comments at 49-51; National Grid Initial Comments at 36-37; PG&E Initial Comments at 2, 11; PPL Initial Comments at 34; SoCal Edison Initial Comments at 2; WIRES Initial Comments at 16; *see also* LS Power Initial Comments at 74-76 (discussing FPA section 205 rights in various regions); PJM Initial Comments at 30 (questioning whether there are any "regional differences" on this policy issue). *But see* Idaho Power Initial Comments at 12 (urging the Commission to ensure that any proposed reforms provide sufficient flexibility to tailor transmission planning and cost allocation processes to accommodate unique regional characteristics).

[3320] ELCON Initial Comments at 21-22; *see also* DATA Reply Comments at 14 (arguing that "the Order No. 1000 status quo creates an inexorable drive towards minimalist, short-term solutions"). Despite its opposition to the NOPR proposal, ELCON sees some potential benefit of encouraging joint ownership and cooperation-based approaches, which ELCON thinks may help remedy the "'us versus them' problems with

reforms under Order No. 1000 often prevent information sharing about transmission needs and available solutions, and lead to less cooperation and coordination within transmission planning regions.[3321] Harvard ELI disagrees, however, arguing that the report cited by WIRES provides evidence that information asymmetry, secrecy, and utilities' incentives demonstrate undue discrimination.[3322]

1557. Though it does not support the NOPR proposal, Cypress Creek contends that Order No. 1000 led to misaligned incentives such that "competition today has not necessarily fostered just and reasonable rates."[3323] Similarly, American Municipal Power states that many municipal electric systems are located on the fringe of an incumbent transmission provider's system and would significantly benefit from regional transmission projects that improve reliability, although because such projects require coordination between two incumbent transmission providers, they are "largely ignored."[3324] American Municipal Power also states that another disincentive to incumbent transmission provider regional transmission facility development is the

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the current regional planning process." ELCON Initial Comments at 23-24.

[3321] WIRES Supplemental Comments at 4 (citing Rob Gramlich, Richard Doying, & Zach Zimmerman, Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)).

[3322] Harvard ELI Supplemental Comments at 5.

[3323] Cypress Creek Reply Comments at 16.

[3324] American Municipal Power Initial Comments at 31-32.

possibility of losing the project to another developer through the competitive process.[3325] While not taking a position on competitive transmission development processes, Indiana Commission agrees that Order No. 1000 has produced unintended consequences, including that transmission development now mostly takes the form of transmission facilities not subject to competitive transmission development processes,[3326] and states that little region-wide economic transmission development is occurring.[3327]

1558. But some commenters, such as NextEra, contend that if regional transmission investment has lagged behind expectations under Order No. 1000, that is a planning issue, not an incentives issue, and that some of the NOPR's proposed transmission planning reforms will help lead to greater investment in regional transmission facilities.[3328] LS Power argues that the NOPR only generally observed that there have

[3325] *Id.* at 32. However, American Municipal Power states that because regional transmission facilities typically traverse more than one incumbent transmission provider's service territory, allowing individual incumbent transmission providers to exercise a federal right of first refusal without other reforms also designed to promote coordination and cooperation between such providers would not "result in a shift from local to regional projects." *Id.* (referencing the "interzonal nature of regional projects").

[3326] Indiana Commission Initial Comments at 12 (referring to "'immediate need reliability' or 'end of life replacement' or 'supplemental' or 'other'" types of transmission facility projects).

[3327] *Id*.

[3328] *See* NextEra Initial Comments at 18-19, 25; *see also id.* at 43 (arguing that the NOPR proposal is insufficiently based on speculation about potentially flawed investment incentives); Americans for Fair Energy Prices Reply Comments at 5-6; Northwest and Intermountain Initial Comments at 19-20 (arguing that even a limited or conditional right of first refusal eliminates any incentive for the incumbent transmission provider to reduce costs or delays); Ohio Commission Federal Advocate Initial Comments at 18 (arguing that adopting the NOPR proposal would further misalign

been increases in local transmission facility investment and static or declining investment in regional transmission facilities, and did not specify particular transmission planning regions in which this problem is occurring or which incumbent transmission providers face perverse investment incentives.[3329] However, other commenters, such as WIRES, contend that the elimination of federal rights of first refusal may be connected to flat or declining regional transmission investment,[3330] as suggested by the NOPR.

1559. Finally, several commenters argue that the Commission should not adopt federal right of first refusal reforms in this docket, but rather explore those and related issues in another forum. Advanced Energy United, Advanced Energy Buyers, State Agencies, and California Commission, for example, urge the Commission to consider these issues either in a different proceeding or at a technical conference.[3331] Competition Advocates support alternative reforms that they argue can better address the problem of perverse incentives,

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incentives for incumbent transmission providers, not improve them).

[3329] LS Power Initial Comments at 73-74. *But see* PJM Initial Comments at 30 (questioning whether there are any "regional differences" on this policy issue).

[3330] WIRES Reply Comments at 2 (citing WIRES Initial Comments at 13-14).

[3331] Advanced Energy Buyers Initial Comments at 4 n.6; AEE Initial Comments at 4, 35-37; AEE Reply Comments at 31-33; California Commission Initial Comments at 103-104; State Agencies Initial Comments at 11; State Agencies Reply Comments at 6; *see also* Chemistry Council Initial Comments at 8; Enel Initial Comments at 3; Harvard ELI Initial Comments at 7-10; NESCOE Initial Comments at 11, 74-77.

including better enforcement of existing orders or taking action to reduce Order No. 1000 exemptions, and establishing an independent transmission monitor.[3332]

### 2. Comments on the NOPR's Joint Ownership Proposal

1560. Some commenters, including TAPS, highlight various ways in which the Commission's joint ownership proposal would alleviate challenges associated with current regional transmission planning processes.[3333] Some commenters, such as ELCON and the Omaha Public Power District, argue that the Commission's joint ownership proposal would benefit customers or encourage incumbent transmission providers to pursue larger and more comprehensive transmission solutions to the benefit of customers, and create incentives for transmission providers to find beneficial opportunities and investments for joint ownership partners and customers.[3334] Other commenters agree that

[3332] Competition Advocates Supplemental Comments at 3-4.

[3333] *See* TAPS Initial Comments at 29-30 (stating that joint ownership arrangements provide benefits such as "improving transmission planning to produce a more efficient build-out; facilitating state siting; making it easier for [load-serving entities] to accept cost increases associated with new transmission by providing a hedge; and reducing the costs of needed facilities"), *id.* at 34-37; *see also* Eversource Initial Comments at 36-39; Pattern Energy Initial Comments at 37; PPL Initial Comments at 32-33; Vermont Electric and Vermont Transco Initial Comments at 4.

[3334] *See* ELCON Initial Comments at 23-24; *see also* Cross Sector Representatives Supplemental Comments at 1 (arguing that the provisions are appropriately tied to collaborative and holistic planning outcomes that provide clear benefits to customers and would benefit the goals enunciated by the Commission throughout this rulemaking process); Omaha Public Power Initial Comments at 5 (suggesting that the joint ownership proposal will likely encourage neighboring incumbent transmission providers to develop facilities that benefit multiple transmission providers under certain conditions); Pattern Energy Initial Comments at 37 (asserting that joint ownership arrangements will open the market to additional investment opportunities for all parties).

adopting the NOPR proposal may incentivize incumbent transmission providers to "look beyond the provincial" needs and consider regional and interregional solutions to transmission needs.[3335]

1561. However, numerous commenters criticize the NOPR proposal and its approach to joint ownership partner selection, especially its inclusion of another incumbent transmission provider as a potential joint ownership partner.[3336] In general, these commenters contend that incumbent transmission providers would be free to only team up with fellow incumbent transmission providers with the same interests and exclude others, leading to results that would be contrary to the goals of Order No. 1000. As Anbaric states, two incumbent transmission providers (or their affiliates) could "team up and swap a portion of their respective projects as a means to satisfy the joint ownership requirement" and thereby "maintain the status quo"[3337] rather than advance innovation, cost savings, or new entry. NextEra and others decry this potential outcome, which could

[3335] Tabors Caramanis Rudkevich Initial Comments at 2; *see also* Citizens Energy Initial Comments at 9-10; PG&E Initial Comments at 11 (arguing that a conditional federal right of first refusal will help mitigate development challenges by promoting collaboration between partners).

[3336] *E.g.*, Anbaric Initial Comments at 18; *see also, e.g.*, APPA Initial Comments at 11-12; California Commission Initial Comments at 80-88; Competition Coalition Initial Comments at 49-50; LS Power Initial Comments at 92-94; Massachusetts Attorney General Initial Comments at 48-49; New Jersey Commission Initial Comments at 31-33; NextEra Initial Comments at 49-51; NRECA Initial Comments at 58, 61; PJM States Initial Comments at 14; Policy Integrity Initial Comments at 21-22; TANC Initial Comments at 13; TAPS Initial Comments at 48-51; TAPS Reply Comments at 5-6 & n.25.

[3337] Anbaric Initial Comments at 18.

keep nonincumbent transmission developers from obtaining investment opportunities.[3338] Relatedly, several commenters argue that the NOPR proposal would raise antitrust and competition concerns,[3339] including US DOJ and FTC, which argue that because the joint venture will not be facing pressure to compete, the conditional federal right of first refusal does not create the incentive for incumbent transmission providers to seek out the best partner.[3340] In other words, US DOJ and FTC argue, the mere existence of a joint venture partner does not bring competition to a project, nor does it necessarily result in the best partner for a project being selected, in terms of skill, cost, or innovation.[3341]

1562. Commenters also highlight the potential for uncertainty, litigation, and delays in attempting to implement the NOPR proposal. Anbaric asserts that a conditional federal right of first refusal could add delays due to litigation over whether incumbent transmission providers provided meaningful opportunities to third parties.[3342] EEI

[3338] *See* Harvard ELI Initial Comments at 35; NextEra Initial Comments at 49-51. In contrast, some commenters such as APPA urge the Commission to adopt a requirement that incumbent transmission providers offer joint ownership on reasonable terms at a load ratio share level to all unaffiliated load-serving entities in the incumbent transmission provider's footprint. *See* APPA Reply Comments at 5-6; TAPS Initial Comments at 30-32 (advocating for a similar proposal).

[3339] *See, e.g.*, Competition Coalition Initial Comments at 59-62; LS Power Initial Comments at 122-125, 131-134; US DOJ & FTC Initial Comments at 17-18.

[3340] US DOJ & FTC Initial Comments at 17.

[3341] *Id.* at 17-18; *see also* LS Power Initial Comments at 93 (arguing that the NOPR proposal would not require any independent check that the incumbent transmission provider is partnering with the entity that offers the most benefits).

[3342] Anbaric Initial Comments at 16; *see also* Avangrid Initial Comments at 18 (noting that establishing a conditional federal right of first refusal adds a layer of

cautions against putting transmission providers in a position where they must adjudicate what constitutes meaningful ownership of jointly owned transmission facilities on a case-by-case basis, recommending instead that the Commission provide guidance on the types of ownership rights or operational obligations that will qualify and establish a process for seeking Commission approval in a timely manner for other arrangements.[3343] MISO asserts that the process envisioned by the NOPR would be time-consuming, as would developing a joint ownership proposal, and asks that the Commission adopt clearly defined criteria for joint ownership, such as a *pro forma* agreement, in order not to impede transmission development.[3344] National Grid calls for planning authorities to be given the authority to determine the appropriate criteria and conditions that constitute a valid joint ownership arrangement, though it also asks for guidance regarding particular types of combinations of potential joint owners.[3345]

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complexity to the development of transmission); NYISO Initial Comments at 55-56 (asking the Commission to consider the complications, disputes, and delays that may arise from attempting to implement a conditional federal right of first refusal and other practical issues).

[3343] EEI Initial Comments at 36-37; *see also* Ameren Initial Comments at 44; DATA Initial Comments at 21-22; PJM Initial Comments at 4-5, 51-52, 53-54.

[3344] MISO Initial Comments at 80-83; *see also* APPA Initial Comments at 4-7, 20-22 (outlining a detailed proposed implementation process by which APPA believes incumbent transmission providers and load-serving entities could work together and help avoid disputes and delay); Invenergy Reply Comments at 7-8 (calling for the adoption of *pro forma* agreements to ease implementation); TAPS Initial Comments at 53-54 (expressing concern that the NOPR proposal's anticipated period for formulation of joint ownership agreements is too short).

[3345] *See* National Grid Initial Comments at 37.

### C. Commission Determination

1563. We decline to act at this time to finalize the NOPR proposal. Rather, we will continue to consider the NOPR proposal and potential federal right of first refusal issues in other proceedings. We do not adopt in this final rule any changes to Order No. 1000's nonincumbent transmission developer reforms.

1564. As summarized above, commenters raise substantial concerns about whether incumbent transmission providers, as a result of Order No. 1000's reforms, face perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint. To the extent that incumbent transmission providers face perverse investment incentives, commenters also raise substantial concerns about whether the NOPR proposal adequately and appropriately addresses those incentives and whether adopting the proposal is necessary or appropriate in carrying out the provisions of the FPA. Therefore, after careful consideration of the record, we decline to finalize the NOPR proposal at this time. The Commission will continue to consider potential federal right of first refusal reforms along with other transmission reforms in the future.[3346]

[3346] We note, for example, the ongoing proceeding in Docket No. AD22-8 on Transmission Planning and Cost Management.

# IX. Local Transmission Planning Inputs in the Regional Transmission Planning Process

## A. Need for Reform

### 1. NOPR

1565. In the NOPR, the Commission explained that it was concerned that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders, and that regional transmission planning processes may not adequately coordinate with local transmission planning processes.[3347] The Commission stated in the NOPR that it was concerned that the lack of minimal standards or specified procedures may contribute to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.[3348] Accordingly, the Commission stated that it believed reforms to better ensure transparency and opportunities for stakeholder engagement may be timely and important in light of the significant investments in transmission that now occur through local transmission planning processes.[3349]

[3347] NOPR, 179 FERC ¶ 61,028 at P 398 & n. 639 (providing that regional transmission planning processes should identify "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual utility transmission providers in their local transmission planning process" (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 148)).

[3348] *Id*.

[3349] *See supra* The Overall Need for Reform section.

1566. In addition, the Commission explained in the NOPR that it was concerned that, given the age of the nation's transmission infrastructure, many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address regional transmission needs, and, more generally, that transmission providers developing regional transmission plans may lack the information necessary to identify the benefits that regional transmission facilities may provide in deferring or eliminating the need for in-kind replacements. Specifically, the NOPR stated that in-kind replacements of existing transmission facilities are managed by individual incumbent transmission providers according to their company practices, and that there is no requirement that transmission providers plan these in-kind replacement transmission facilities through an Order No. 890-compliant transmission planning process.[3350] The Commission stated that, because in-kind replacement of existing transmission facilities is not subject to any transmission planning process, it was concerned that, absent reform, there may be a lack of coordination between regional transmission planning processes and in-kind replacement of existing transmission facilities to identify whether these replacement transmission facilities could be modified to more efficiently or cost-effectively address

[3350] NOPR, 179 FERC ¶ 61,028 at P 399 (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at P 33; *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020)).

transmission needs identified through Long-Term Regional Transmission Planning. The Commission explained that this lack of coordination may result in a regional transmission planning process that fails to identify opportunities to right size planned in-kind replacement transmission facilities and may result in the development of duplicative or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.[3351]

**2. Comments**

1567. Some commenters argue that the NOPR proposal regarding improved transparency in local transmission planning processes is not justified.[3352] EEI argues that the Commission has not found that any of the approved transmission planning processes under Order Nos. 890 and 1000 are unjust and unreasonable or unduly discriminatory or preferential and that, absent such a finding, the Commission should not move forward with changes to local transmission planning processes.[3353] Idaho Power states that the Commission should not use a general rulemaking to address localized problems.[3354] On the other hand, Indicated PJM TOs state that the NOPR proposal to enhance transparency

[3351] *Id*.

[3352] Dominion Initial Comments at 76 (citing NOPR, 179 FERC ¶ 61,028 at P 395 n.634); EEI Initial Comments at 40; Idaho Power Initial Comments at 12-13.

[3353] EEI Initial Comments at 40; *see also* Dominion Initial Comments at 76.

[3354] Idaho Power Initial Comments at 12-13.

in the local transmission planning processes is needed in each transmission planning region to satisfy the requirements set forth by Order No. 890.[3355]

1568. With respect to the Commission's proposed right-sizing reforms, LS Power and NextEra argue that the NOPR fails to make findings required under FPA section 206 to permit a right of first refusal for right-sized projects. LS Power and NextEra assert that the NOPR does not satisfy the first prong of FPA section 206, as it fails to make an affirmative finding that either the regional transmission planning process or the local transmission planning process are unjust and unreasonable such that abandonment of the existing tariff provisions is warranted.[3356] Competition Coalition also asserts that the Commission failed to demonstrate the alleged need for reform on any section 206 finding.[3357]

### 3. Commission Determination

1569. Based on the record, we find that there is substantial evidence to support the conclusion that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning

[3355] Indicated PJM TOs Initial Comments at 41 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 426-561).

[3356] LS Power Initial Comments at 50-53 (citations omitted); NextEra Initial Comments at 54-56 (citations omitted). A number of commenters challenge the NOPR right-sizing proposal, including the proposal to permit a federal right of first refusal for certain replacement facilities. We address those arguments below in the Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities section below.

[3357] Competition Coalition Initial Comments at 64.

processes are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform of the local transmission planning process and coordination between the local and regional transmission planning processes, including the evaluation of whether replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs.[3358]

1570. Local and regional transmission planning processes serve essential and complementary roles in ensuring that customers' transmission needs are identified and met at a just and reasonable cost, including through the identification, evaluation, and selection of more efficient or cost-effective transmission solutions through regional transmission planning. Information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning, and it is therefore critical that the processes are appropriately designed and aligned to ensure that transmission providers and stakeholders have the information needed, including from the local transmission planning process, to conduct effective regional transmission planning. While the broader reforms directed in this final rule are focused on improving the regional transmission planning process, we nonetheless have identified discrete deficiencies in the local transmission planning process and its coordination with the

[3358] Below, we clarify that the new transparency requirements do not apply to transmission facilities that are otherwise exempt from Order No. 890's transparency requirements, such as asset management projects. *See infra* Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

regional transmission planning process that also must be addressed to ensure that Commission-jurisdictional rates are just and reasonable.

1571. First, we find that local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders. The Commission has recognized the critical role that stakeholders serve in effective transmission planning,[3359] and in Order Nos. 890 and 1000, directed reforms to facilitate their meaningful participation in both local and regional transmission planning.[3360] However, the record demonstrates that existing transparency and coordination requirements in local transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.[3361] We further find that the absence of minimal standards or specified procedures to implement the

[3359] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 454 ("[C]ustomers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input."); Order No. 1000, 136 FERC ¶ 61,051 at P 152 ("[A]bsent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.").

[3360] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152.

[3361] *E.g.*, OMS Initial Comments at 15 ("OMS members have varying levels of oversight and visibility into the utility-driven, local planning processes that are incorporated into the overall MISO transmission expansion plan."); Concerned Scientists ANOPR Initial Comments at 24-31 (discussing challenges obtaining information to assess projects developed through local transmission planning processes) (citations omitted); New Jersey Commission ANOPR Initial Comments at 6-7 (discussing limited information and analysis provided regarding projects considered in local transmission planning) (citations omitted).

transmission planning principles required by Order No. 890 contributes to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.

1572. The combined effect of these deficiencies is that stakeholders who wish to participate in transmission planning, at both the local and regional level, may not be able to effectively do so. More specifically, we find that, when engaging in the regional transmission planning process, stakeholders lack sufficient information about underlying local transmission needs and potential solutions that is necessary to ensure that the more efficient or cost-effective regional transmission solutions are identified, evaluated, and selected. Given the recognized importance of stakeholder participation in effective transmission planning, we find that reforms are needed to ensure that Commission-jurisdictional local and regional transmission planning processes remain just, reasonable, and not unduly discriminatory or preferential. Furthermore, we believe that reforms to better ensure more consistent implementation of the Order No. 890 transmission planning principles are timely and important in light of the significant investments in transmission infrastructure that now occur through local transmission planning processes.[3362]

1573. Second, we find that additional coordination between the local and regional transmission planning processes regarding replacement of aging infrastructure is needed. The record shows that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life. For example, we note

[3362] *See supra* The Overall Need for Reform section.

that PJM estimated that roughly two-thirds of all PJM transmission system assets are more than 40 years old, with some transmission facilities approaching 90 years old.[3363] NYISO highlights that 80 percent of transmission lines in its footprint are at least 50 years old and are either being replaced or will soon need to be replaced.[3364] Replacing these transmission facilities will require substantial investment, which will directly affect Commission-jurisdictional transmission rates. For example, the California Commission notes that PG&E anticipates spending roughly $11 billion between 2022 and 2027 to address aging transmission infrastructure.[3365]

1574. However, because the Commission's existing requirements do not obligate transmission providers to share sufficient information regarding these replacement projects, transmission providers in the regional transmission planning process are not consistently evaluating whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs. We therefore find that the lack of a requirement for transmission providers in each

[3363] *See* PJM Interconnection, L.L.C., *The Benefits of the PJM Transmission System* 5 (2019), https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf. Moreover, AEP estimates that approximately 30 percent of its line miles and circuit breakers will need to be replaced over the next 10 years. *See* AEP, *Wolfe Utilities, Midstream, & Clean Energy Conference* 40 (Sept. 30, 2021), https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/WolfeConferencePresentation093021.pdf.

[3364] NYISO Initial Comments at 58.

[3365] California Commission Initial Comments at 110.

transmission planning region to evaluate whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address Long-Term Transmission Needs results in a regional transmission planning process that fails to identify opportunities to right-size planned in-kind replacement transmission facilities and may result in the development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.

1575. With respect to the claim by commenters that the Commission lacks jurisdiction to impose the proposed transparency and coordination requirements or that the Commission has not justified the requirements,[3366] we disagree. Consistent with Order Nos. 890 and 1000, the Commission has authority to establish requirements related to local transmission planning processes and the inputs to regional transmission planning processes.[3367] Our findings above are supported by substantial evidence in the record, and we address any concerns regarding our remedy to address the transparency and coordination deficiencies below.

[3366] Dominion Initial Comments at 76; EEI Initial Comments at 40; Idaho Power Initial Comments at 12-13.

[3367] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 435 ("In order to limit the opportunities for undue discrimination . . . and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level."); Order No. 1000, 136 FERC ¶ 61,051 at PP 68, 148, 152.

1576. We also disagree with LS Power, Competition Coalition, and NextEra's arguments regarding whether the Commission properly demonstrated under FPA section 206 that existing rates are unjust, unreasonable, or unduly discriminatory or preferential in instituting a federal right of first refusal for right-sized replacement transmission facilities.[3368] First, we clarify that the Commission is not finding that existing transmission planning processes are unjust, unreasonable, or unduly discriminatory or preferential due to a lack of a federal right of first refusal for these facilities. Rather, we find here that transmission providers' OATTs are unjust and unreasonable due to the lack of right-sizing requirements that may lead to the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. As discussed above, the record demonstrates that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating, through the regional transmission planning process, whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs. As a result of this identified deficiency, we find that transmission providers' OATTs are unjust and unreasonable. We address LS Power, NextEra, and other commenters' concerns regarding the Commission's proposed replacement rate, including our findings regarding a federal right of first refusal for right-sized replacement transmission facilities, below.

[3368] Competition Coalition Initial Comments at 64; LS Power Initial Comments at 51-53; NextEra Initial Comments at 54-56.

1577. Because we find that the Commission's existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206, that transmission providers adopt, with certain modifications, the two reforms that the Commission identified in the NOPR: (1) enhance the transparency of local transmission planning processes; and (2) require transmission providers to evaluate whether transmission facilities that need replacing can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.[3369] We find that the first reform will result in transmission providers providing enhanced transparency for stakeholders while providing those same stakeholders with opportunities to more effectively engage in local and regional transmission planning processes. We find that the second reform will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Taken together, we find that these reforms will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

[3369] NOPR, 179 FERC ¶ 61,028 at PP 400-403.

### B. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process

#### 1. NOPR Proposal

1578. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[3370] The Commission explained that transmission providers would be required to establish an iterative process that would provide stakeholders with meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process.[3371] The Commission proposed to require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before a transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.[3372]

[3370] NOPR, 179 FERC ¶ 61,028 at P 400.

[3371] *Id*.

[3372] *Id*.

1579. Specifically, the Commission proposed to require transmission providers in each transmission planning region, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers that are members of the transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, the Commission proposed to require that, no fewer than 25 calendar days after the Needs Meeting, transmission providers that are members of the transmission planning region convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). The Commission also proposed to require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.[3373]

[3373] *Id.* P 401.

1580. The Commission preliminarily found that these proposed requirements will result in needed additional transparency into local transmission planning processes, which inform the regional transmission planning process in a transmission planning region.[3374]

### 2. Comments

#### a. Interest in Enhanced Transparency of Local Transmission Planning Inputs

1581. Many commenters support the NOPR proposal.[3375] ITC argues that the Commission's proposed transparency requirements strike an appropriate balance between the need for oversight and the need to timely address asset management needs.[3376] Southeast PIOs state that closer coordination between the regional and local transmission planning processes would help to ensure that the local process does not dull the

[3374] *Id.* P 402.

[3375] *See* AEE Initial Comments at 3; AEP Reply Comments at 10; APPA Initial Comments at 47; Breakthrough Energy Initial Comments at 19; Center for Biological Diversity Initial Comments at 28; Certain TDUs Initial Comments at 13; City of New Orleans Council Initial Comments at 11; Clean Energy Associations Initial Comments at 36; Clean Energy Buyers Initial Comments at 33; Colorado Consumer Advocates Initial Comments at 30-31; Cross Sector Representatives Supplemental Comments at 1; Exelon Initial Comments at 3, 51-52; Indicated PJM TOs Initial Comments at 40; Interwest Initial Comments at 17-18; ITC Initial Comments at 45-47; National and State Conservation Organizations Initial Comments at 2; New York Transco Initial Comments at 1; NextEra Initial Comments at 66-67; Northwest and Intermountain Initial Comments at 20; OMS Initial Comments at 16; PJM States Initial Comments at 4-6; Resale Iowa Initial Comments at 8; Resale Iowa Reply Comments at 5; SEIA Initial Comments at 25-26; Shell Initial Comments at 34; Southeast PIOs Initial Comments at 54-55; Vermont State Entities Initial Comments at 10.

[3376] ITC Initial Comments at 45-47 (citations omitted).

effectiveness of the regional process.[3377] Vermont State Entities support enhancing transparency and visibility of local transmission planning processes and coordinating with Long-Term Regional Transmission Planning and other processes, including the generator interconnection process.[3378] City of New Orleans Council states that increased transparency, collaboration, and coordination between the regional and local transmission planning processes will result in more efficient local transmission development.[3379] OMS asserts that enhanced transparency will enable retail regulators to more effectively participate in identifying the best set of projects to meet both local and regional needs.[3380]

1582. Colorado Consumer Advocates state that the Commission must ensure that transmission providers maintain coordinated, open, and transparent transmission planning processes on both a local and regional level that meet stakeholder needs.[3381] Interwest asserts that the NOPR proposal is needed to incentivize the coordination of generation and resource planning and transmission planning beyond state lines, adding that transparency measures, such as a process for information sharing, could allow customers

[3377] Southeast PIOs Initial Comments at 54-55.

[3378] Vermont State Entities Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

[3379] City of New Orleans Council Initial Comments at 11.

[3380] OMS Initial Comments at 16.

[3381] Colorado Consumer Advocates Initial Comments at 17, 20-21.

or stakeholders to evaluate or replicate the findings from transmission providers and reduce after-the-fact disputes regarding allocated costs.[3382]

1583. Exelon and Indicated PJM TOs note that the NOPR proposal mirrors PJM TOs' local transmission planning process.[3383] Indicated PJM TOs state that the NOPR proposal will help to ensure the coordination of local and regional transmission planning while preserving transmission owner responsibility for local transmission planning.[3384] Indicated PJM TOs state that the PJM Attachment M-3 process avoids duplication of projects between local and regional transmission planning processes.[3385] Clean Energy Associations state that each transmission planning region should have the opportunity to regularly review local transmission planning criteria for consistency with regional transmission planning, as PJM's manuals require.[3386]

1584. Clean Energy Buyers state that existing local transmission planning has not met expectations for openness, coordination, and transparency, and that the NOPR proposal will help remedy such deficiencies and better identify cost-effective transmission

[3382] Interwest Initial Comments at 17-18. As an example, Interwest cites WestConnect's Colorado Coordinated Planning Group, which conducts transmission planning through task forces and work groups consisting of stakeholders. *Id*.

[3383] Exelon Initial Comments at 3-4, 51-52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0)); *see* Indicated PJM TOs Initial Comments at 42-43.

[3384] Indicated PJM TOs Initial Comments at 42-43.

[3385] *Id.* at 42.

[3386] Clean Energy Associations Initial Comments at 37 (citing PJM Manual 14B, section 1.1 Planning Process Work Flow).

projects.[3387] Northwest and Intermountain agree that the Commission should reform local transmission planning processes to enhance transparency and provide meaningful opportunities for public input.[3388] Similarly, Resale Iowa asserts that MISO's stakeholder processes do not address local transmission planning issues, especially those related to asset management, end-of-life, and other forms of local transmission planning that are exempt from Order No. 890's transmission planning requirements. Thus, Resale Iowa contends, its members believe they must bear the cost of new or upgraded transmission facilities without the opportunity to discuss less costly alternatives.[3389]

1585. National and State Conservation Organizations suggest that early and consistent community engagement are key elements to successful development and timely completion of transmission projects, as the voices and concerns of affected local communities must be heard and acted upon to prevent environmental injustices and environmental damage.[3390] WE ACT states that, in addition to coordination with state entities, there must also be meaningful engagement and robust input from affected and overburdened communities so that states and transmission providers are aware of the potential harms of siting transmission projects in environmental justice communities. WE ACT recommends that the Commission, its Office of Public Participation, state

[3387] Clean Energy Buyers Initial Comments at 33.

[3388] Northwest and Intermountain Initial Comments at 20.

[3389] Resale Iowa Reply Comments at 4-5.

[3390] National and State Conservation Organizations Initial Comments at 2.

officials, and transmission providers familiarize themselves with several key documents relating to environmental justice to ensure meaningful community engagement and to inform comprehensive environmental justice analyses to reduce or eliminate undue burdens.[3391]

**b. Suggested Modifications to the NOPR Proposal**

1586. Some commenters support the NOPR proposal, but also suggest modifications to make it more effective or request that the Commission provide flexibility for transmission planning regions to determine the best manner to meet the requirements.[3392] NARUC requests flexibility for transmission planning regions to determine the timeline for stakeholder processes.[3393] NRECA requests that the Commission allow transmission planning regions that currently have transparent processes to maintain them.[3394]

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[3391] WE ACT Initial Comments at 5-6 (citing U.S. Env't Prot. Agency, *Promising Practices for EJ Methodologies in NEPA Reviews* (Mar. 2016), https://www.epa.gov/environmentaljustice/ej-iwg-promising-practices-ej-methodologies-nepa-reviews; U.S. Env't Prot. Agency, *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* (June 2016), https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf; *The Principles of Environmental Justice (EJ)*, Energy Justice Network, https://www.ejnet.org/ej/principles.pdf; *Jemez Principles of Democratic Organizing*, Energy Justice Network, https://www.ejnet.org/ej/jemez.pdf).

[3392] *See* ACORE Initial Comments at 18-19; AEP Initial Comments at 7, 40-41, 43-44; Ameren Initial Comments at 46-47; NARUC Initial Comments at 58-59; NESCOE Initial Comments at 77-78; North Carolina Commission and Staff Initial Comments at 18-20; NRECA Initial Comments at 65-66; NYISO Initial Comments at 9, 57-58; TANC Initial Comments at 11; WE ACT Initial Comments at 5-6; WIRES Initial Comments at 8-10.

[3393] NARUC Initial Comments at 58-59 (citing NOPR, 179 FERC ¶ 61,028 at PP 400-401).

[3394] NRECA Initial Comments at 65-66; *see also* Ameren Initial Comments at 46

1587. TANC encourages the Commission to provide regional flexibility by allowing transmission providers to propose on compliance alternative frameworks for consideration of local transmission plans in the regional transmission planning process and allow transmission planning regions to consider the burden versus benefit of such as a requirement to maximize transparency and project efficiencies.[3395]

1588. NESCOE contends that aspects of the proposal are too prescriptive, such as the Commission dictating the number of stakeholder meetings. However, NESCOE states that enhanced transparency could help states and ratepayers better understand proposed transmission facilities and the costs associated with them.[3396] NESCOE states that stakeholders should have meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process, asserting that transmission owners in ISO-NE currently do little more than present their proposals for in-kind replacements of existing transmission infrastructure to ISO-NE's Planning Advisory Committee.[3397]

1589. ACORE states that the proposed stakeholder involvement in local transmission planning is beneficial but that the NOPR proposal lacks clarity on whether transmission

(citing Ameren ANOPR Initial Comments at 20-21).

[3395] TANC Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at PP 400, 402).

[3396] NESCOE Initial Comments at 77-78 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

[3397] *Id.*; NESCOE Reply Comments at 6 (citation omitted).

providers must consider local transmission projects alongside other options in Long-Term Regional Transmission Planning.

1590. Joint Consumer Advocates argue that, while the NOPR proposal will increase transparency, it will not address the inability of consumer advocates to meaningfully review planning inputs or models because the inputs are not maintained in a format that enables stakeholders to review them, understand the assumptions, or replicate the transmission planning results, as contemplated in Order No. 890.[3398] Pine Gate recommends that the Commission require that transmission providers make available to stakeholders information about the local transmission planning process for review and comment prior to the finalization or approval of the local transmission plan.[3399]

### c. Concern with the NOPR Proposal

1591. Several commenters state that they oppose or have concerns with the NOPR proposal.[3400] Ohio Commission Federal Advocate argues that the NOPR proposal is of limited value given that it does not require a more comprehensive review of local

[3398] Joint Consumer Advocates Initial Comments at 21-22.

[3399] Pine Gate Initial Comments at 49-50.

[3400] *See* American Municipal Power Initial Comments at 13-25; APS Initial Comments at 12-13; Avangrid Initial Comments at 13-15; CAISO Initial Comments at 7, 47-51; California Water Initial Comments at 5-8; DC and MD Offices of People's Counsel Initial Comments at 6-7; Dominion Initial Comments at 69-70; EEI Initial Comments at 40; Eversource Initial Comments at 47-49; Idaho Power Initial Comments at 12-13; MISO Initial Comments at 84-86; MISO TOs Initial Comments at 28-31; National Grid Initial Comments at 39-40; New York TOs Initial Comments at 16-17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 15-18; PPL Initial Comments at 35-36; Xcel Initial Comments at 16-17.

transmission projects; instead, these projects will continue to be chosen, designed, and approved by the transmission owner.[3401] Similarly, American Municipal Power states that new transmission projects that expand or enhance the transmission grid and have regional benefits should be planned by the regional transmission entity and not by individual transmission owners. Further, American Municipal Power asserts that use of the PJM Attachment M-3 process, which American Municipal Power contends the NOPR "essentially" proposes to require nationwide, has resulted in additional balkanization of the transmission planning process, has increased the problem of planning based on individual transmission owners' criteria for determining need, and has disenfranchised PJM as the regional transmission planner.[3402]

1592. Relatedly, Pennsylvania Commission states that enhancing transparency in local transmission planning is a laudable goal but notes that the proposal will not enhance PJM's process because the NOPR proposal adopts the existing PJM Attachment M-3 process.[3403]

1593. Several commenters argue that the existing regional transmission planning process in their transmission planning region is already transparent and therefore oppose the

[3401] *See* Ohio Commission Federal Advocate Initial Comments at 20-21 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 16)).

[3402] American Municipal Power Initial Comments at 17; *see* American Municipal Power Supplemental Comments at 1, 6 (citations omitted).

[3403] Pennsylvania Commission Initial Comments at 20-21 (citing NOPR, 179 FERC ¶ 61,028 at PP 399-400).

NOPR proposal.[3404] New York TOs assert that New York's regional and local transmission planning processes almost fully satisfy the proposed requirements and, as such, the Commission should allow NYISO to retain these processes.[3405] MISO argues that the additional requirements proposed in the NOPR are not needed in an RTO such as MISO with a fully developed, open, and transparent transmission planning process in effect.[3406] MISO TOs agree, stating that MISO's existing processes provide for transparency in local transmission planning through subregional planning meetings, published materials, and workshops throughout the transmission planning process.[3407]

1594. CAISO states that the Commission should not disrupt existing processes that are working efficiently, arguing that its transmission planning process already considers both local and regional assumptions, needs, and solutions as part of a single integrated

[3404] APS Initial Comments at 12-13; Avangrid Initial Comments at 13-15; CAISO Initial Comments at 46-50; Dominion Initial Comments at 69; Eversource Initial Comments at 46-49; MISO Initial Comments at 84-86; MISO TOs Initial Comments at 29-31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16-17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16-18.

[3405] New York TOs Initial Comments at 7.

[3406] MISO Initial Comments at 84-85.

[3407] MISO TOs Initial Comments at 29-31 (citing MISO Business Practice Manual, Transmission Planning, BPM-20, section 4.1; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § I.C.9; MISO, *Subregional Planning Meeting*, https://www.misoenergy.org/engage/committees/subregional-planning-meeting/; *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, at PP 80, 114 (2013), *order on reh'g*, 144 FERC ¶ 61,020 (2013), *order on reh'g & compliance*, 147 FERC ¶ 61,127 (2014), *aff'd sub nom. MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016)).

process.[3408] PG&E agrees that the NOPR proposal is unnecessary for California utilities and CAISO because many CAISO transmission owners already have extensive stakeholder programs. Therefore, PG&E states, the Commission should clarify that transmission providers are not required to enhance the transparency of local transmission planning processes where such transparent processes already exist.[3409]

1595. In addition, PG&E argues that the Commission should revise the NOPR proposal to state that the proposed enhancements to the local transmission planning process should not apply to asset management projects, including in-kind replacements, that are outside the scope of Order No. 890.[3410] PG&E asserts that including asset management projects would significantly increase the volume and complexity of regional and local transmission planning and potentially delay needed repairs and maintenance. PG&E further states that all of PG&E's asset replacement projects are already scrutinized through the annual update to its formula transmission rate.[3411]

1596. Eversource contends that the current local transmission planning process in New England, which is based on the principles in Order No. 890, is largely consistent with the Commission's proposed transparency principles and has worked well.[3412] Similarly, APS

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[3408] CAISO Initial Comments at 47-50 (citations omitted).

[3409] PG&E Initial Comments at 15-18.

[3410] *Id.* at 15-16 (citing *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec.*, 164 FERC ¶ 61,161 at P 66).

[3411] PG&E Reply Comments at 6-7.

[3412] Eversource Initial Comments at 46-47 (citing *ISO New England, Inc.*,

states that it currently uses its local transmission plans in the base model assumptions for its regional transmission planning process and provides stakeholders with an opportunity for input twice a year in public meetings as required by Order No. 890.[3413]

1597. Some commenters request that the Commission adopt a less prescriptive reform that outlines principles or goals for transparency and allow each transmission provider to either explain how its existing local transmission planning process already complies with those principles or propose targeted modifications to bring its existing process into compliance with the new requirements.[3414] New York TOs note that efforts to improve transparency between local and regional transmission planning are beginning in NYISO, and they recommend that the Commission allow NYISO and New York TOs to demonstrate on compliance how any resulting enhancements will meet or exceed any new requirements.[3415] Vermont Electric and Vermont Transco suggest that the Commission adopt a performance-based approach under which the Commission would specify expectations for transparency in local transmission planning processes and then

Transmittal, Docket No. OA08-58 (filed Dec. 7, 2007)).

[3413] APS Initial Comments at 12 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 257-258, 451).

[3414] *See* Avangrid Initial Comments at 15; EEI Initial Comments at 40; Eversource Initial Comments at 48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84; MISO TOs Initial Comments at 31; National Grid Initial Comments at 39; New York TOs Initial Comments at 7, 16-17; Xcel Initial Comments at 17.

[3415] *See* New York TOs Initial Comments at 6-7, 16-17 (citations omitted).

allow transmission providers to determine how they will achieve those goals within longer timelines.[3416]

1598. Several commenters argue that the NOPR proposal is too prescriptive or may interfere with existing processes.[3417] Eversource states that, if the Commission adopts a more prescriptive approach to local transmission planning, it could conflict with existing, state-jurisdictional planning processes for local transmission projects, creating barriers to distribution facility upgrades that are needed to support expanded use of distributed energy resources and load growth from electrification.[3418] Dominion cautions against adding more process when transmission providers already participate in extensive local transmission planning processes that consider Long-Term Regional Transmission Planning and stakeholder positions.[3419] Avangrid agrees, asserting that the NOPR proposal could override existing processes that have been established over years of stakeholder consensus building.[3420] PPL and American Municipal Power state that the

[3416] Vermont Electric and Vermont Transco Initial Comments at 5.

[3417] Avangrid Initial Comments at 13; CAISO Initial Comments at 7-8, 47, 50; Dominion Initial Comments at 70; Eversource Initial Comments at 47-48; MISO Initial Comments at 86; PG&E Initial Comments at 17-18; PPL Initial Comments at 36; Xcel Initial Comments at 16-17.

[3418] Eversource Initial Comments at 49.

[3419] Dominion Initial Comments at 69-70.

[3420] Avangrid Initial Comments at 13.

NOPR proposal may not be appropriate for all transmission planning regions and may interfere with efficient and well-functioning local transmission planning.[3421]

1599. Certain commenters also argue that the NOPR proposal is unduly burdensome.[3422] APS argues that the NOPR proposal could delay local transmission planning and prevent APS from providing necessary services.[3423] National Grid asserts that the NOPR proposal ignores the reality that local transmission planning processes address different needs than the regional transmission planning process. National Grid argues that the proposal will introduce delay and uncertainty in both the local and regional transmission planning processes, disrupting currently effective procedures at a time when participants in the regional transmission planning process should be focused on Long-Term Regional Transmission Planning.[3424]

1600. In addition, National Grid argues that the NOPR proposal will complicate transmission planning because individual transmission providers in each transmission planning region will need to integrate their local transmission planning efforts into the regional transmission planning process. Further, National Grid states that in multi-state RTO/ISO transmission planning regions, it could also lead to second guessing individual

[3421] American Municipal Power Initial Comments at 16; PPL Initial Comments at 36.

[3422] *See* Dominion Initial Comments at 68; Eversource Initial Comments at 49; National Grid Initial Comments at 39-40; Xcel Initial Comments at 16-17.

[3423] APS Initial Comments at 13.

[3424] National Grid Initial Comments at 39-40.

state policies as part of the regional transmission planning process. National Grid also avers that regional transmission planners, such as NYISO and ISO-NE, may not have visibility into the operation of lower voltage local transmission facilities and therefore may not have the expertise that is needed to consider local transmission needs as part of the regional transmission planning process.[3425]

### d. Specific Stakeholder Meeting Requirements

1601. With respect to the length of time between stakeholder meetings, some commenters state that the 25-day minimum period between meetings in the NOPR proposal is too short.[3426] PIOs state the Commission should require transmission providers to submit local transmission planning information, including information concerning planned local transmission projects, with enough time for the regional transmission planning process to effectively find, propose, approve, and construct cost-effective and beneficial regional alternatives where appropriate.[3427]

1602. American Municipal Power contends that the NOPR proposal fails to identify whether and when transmission providers must provide information in advance of the three meetings. Moreover, American Municipal Power argues, 25 days between

[3425] *Id*.

[3426] American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; PIOs Initial Comments at 51-54; TAPS Initial Comments at 6, 62.

[3427] PIOs Initial Comments at 51-52, 54 (citing PIOs ANOPR Initial Comments at 92-94; Concerned Scientists ANOPR Initial Comments at 24-31).

meetings is too short, even assuming all of the models, criteria, and needs are shared with stakeholders sufficiently in advance. Further, American Municipal Power states that the time between the Needs and Solutions Meetings should be based on the time required for transmission providers to incorporate comments received during the Needs Meeting and develop responses.[3428]

1603. Eversource argues that the proposed meeting schedules are not workable in New England, where regional transmission planning studies focus on sub-areas of the transmission system and proceed on different timelines. Moreover, Eversource contends that it is not feasible in New England to have a three-meeting process that aligns with ISO-NE's annual transmission planning cycle because no such annual planning cycle exists.[3429]

1604. Dominion, Eversource, and Xcel state that the three separate stakeholder meetings to review assumptions, needs, and solutions are unnecessary and will increase workload without any benefit.[3430] Xcel contends that a single meeting that addresses the transparency requirements of Order Nos. 890 and 1000, as well as any requirements from the final rule, would be more efficient than the NOPR proposal.[3431] NESCOE asserts that

[3428] American Municipal Power Initial Comments at 24.

[3429] Eversource Initial Comments at 47.

[3430] Dominion Initial Comments at 68; Eversource Initial Comments at 47-48; Xcel Initial Comments at 17.

[3431] Xcel Initial Comments at 16-17.

the final rule should not dictate the number of stakeholder meetings.[3432] MISO states that the Commission should allow each transmission planning region to determine the timing of the iterative meetings, as well as the specific information to be covered at the meetings.[3433]

1605. TAPS states that the Commission should require transmission providers to post their criteria, models, and assumptions so that stakeholders can evaluate or replicate their findings. Moreover, TAPS argues, the Commission should require that transmission providers distribute this information "sufficiently in advance" (and not just "in advance," as the NOPR proposed) of each meeting to allow stakeholders to review and evaluate the information.[3434] Finally, TAPS states that a second Solutions Meeting would provide a meaningful opportunity to consider alternatives.[3435]

1606. Likewise, American Municipal Power recommends that the Commission require a minimum of two Solutions Meetings, with the transmission provider presenting the solutions at the first meeting and the final solution, including alternatives considered, at the second. Further, American Municipal Power recommends that the first Solutions Meeting be no sooner than 90 days after the Needs Meeting and the second Solutions Meeting no sooner than 30 days after the first Solutions Meeting. To the extent the

[3432] NESCOE Initial Comments at 78 (citation omitted).

[3433] MISO Initial Comments at 84.

[3434] TAPS Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

[3435] *Id.* at 62.

Commission does not require a second Solutions Meeting, American Municipal Power recommends that it require transmission providers to provide additional clarity regarding how alternatives were developed and why they were not selected during the single Solutions Meeting.[3436]

1607. While PJM States support requiring Assumptions, Needs, and Solutions Meetings as part of local transmission planning processes, similar to PJM's existing Attachment M-3 process, they express concern that PJM's process is not sufficiently responsive and that the growth of transmission-related costs in PJM is occurring without effective oversight.[3437] PJM States reference PJM's requirement that transmission providers provide information on their local transmission plan and consider any comments received, but state that they are not required to "meaningfully respond to, engage with, or incorporate" these comments.[3438]

1608. California Commission notes that the key elements of the California stakeholder processes that may be relevant for the Commission to consider including in a final rule to increase transparency into local transmission planning include: (1) detailed project and capital expenditure data; (2) ample time to review proposed capital forecasts; (3) the

[3436] American Municipal Power Initial Comments at 24-25.

[3437] PJM States Initial Comments at 4-5 (citing PJM, *2021 Regional Transmission Planning Expansion Plan* 290 (Mar. 2022), https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx).

[3438] *Id.* at 6 (citing PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0), § (c) 1-6).

ability for stakeholders to issue data requests and receive responses; (4) in-depth stakeholder meetings; and (5) consideration of stakeholder comments.[3439]

1609. New England for Offshore Wind argues that all transmission planning processes should include transparency into the evaluation of alternative options that could optimize the performance of renewable energy, as well as justification of proposed transmission projects based on how they compare to no action alternatives.[3440] NRG encourages the Commission to require that the local transmission planning process produce an estimated rate impact for each year if the local transmission plan were to be executed.[3441]

1610. Several commenters contend that transmission providers should be required to respond to comments and questions submitted by stakeholders in the local transmission planning process.[3442] PJM States raise the same issue but look to the relevant RTOs/ISOs to resolve them.[3443]

1611. American Municipal Power and DC and MD Offices of People's Counsel state that transmission providers are not obligated to respond to stakeholder questions, which,

[3439] California Commission Initial Comments at 112-113.

[3440] New England for Offshore Wind Initial Comments at 6.

[3441] NRG Initial Comments at 7, 36.

[3442] *See* American Municipal Power Initial Comments at 18-19; California Commission Initial Comments at 112-113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky Commission Chair Chandler Initial Comments at 22; Northwest and Intermountain Initial Comments at 20-21; TAPS Initial Comments at 62.

[3443] PJM States Initial Comments at 6.

when considered alongside the other barriers to effective participation, creates unnecessary barriers to open communication, is not just and reasonable, and is unduly discriminatory.[3444] American Municipal Power further asserts that comparability principles require transmission providers to consider transmission customers' comments in order to meet their needs and to treat similarly situated customers comparably while conducting transmission system planning.[3445] However, PJM and Indicated PJM TOs disagree that stakeholder comments are being ignored in PJM's Attachment M-3 process.[3446]

1612. TAPS states that dispute resolution on criteria, assumptions, needs, and proposed solutions should be available if stakeholder comments are ignored.[3447] TAPS asserts that the Commission should include such provisions in any final rule or clarify that they are already encompassed in the Commission's transparency proposal.[3448]

**e. Additional Issues**

1613. Pattern Energy and American Municipal Power state that the NOPR proposal does not go far enough in ensuring stakeholder access to transmission planning data from the

[3444] *See* American Municipal Power Initial Comments at 19-20; DC and MD Offices of People's Counsel Initial Comments at 6-7.

[3445] American Municipal Power Initial Comments at 19.

[3446] Indicated PJM TOs Reply Comments at 4, 18-19 (citations omitted); PJM Reply Comments at 13-15 (citing American Municipal Power Initial Comments at 19).

[3447] TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501-503).

[3448] *Id*.

local transmission planning processes and propose additional requirements to make certain information more readily available, subject to execution of a CEII non-disclosure agreement.[3449] Similarly, Pattern Energy states that continued stakeholder access to the source data used in transmission modeling by transmission providers is essential to ensure fair and reasonable outcomes in any transmission planning process.[3450] PPL requests that the Commission clarify that confidential or sensitive information will be protected under the NOPR proposal in the local transmission planning processes as they currently are in PJM.[3451]

1614. Certain TDUs state that the Commission should require transmission providers to coordinate with load-serving entities to transfer data and information and increase transparency in the stakeholder process.[3452] ACEG recommends that the Commission require minimum data transparency standards in the local transmission planning processes, drawing on MISO's and SPP's cost recording and tracking processes for transmission projects approved through their regional transmission planning processes.[3453] Maryland Energy Administration asserts that additional reforms beyond

[3449] *See* American Municipal Power Initial Comments at 22; Pattern Energy Initial Comments at 30-31.

[3450] Pattern Energy Initial Comments at 30-31.

[3451] PPL Initial Comments at 36.

[3452] Certain TDUs Initial Comments at 18.

[3453] ACEG Initial Comments at 56 (citing Johannes Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission:*

those proposed in the NOPR are needed to support transparency and better incorporate stakeholder contributions in local transmission planning processes.[3454] California Water recommends that the Commission allow data requests, similar to the opportunity for data requests in the SoCal Edison and PG&E stakeholder review processes, which ensure that stakeholders can participate and that transmission providers exercise good faith efforts to respond.[3455]

1615. American Municipal Power requests that the Commission direct transmission providers to provide detailed information consisting of more than generic or high-level network models, along with power flow models and power system analyses used in their local transmission planning.[3456] According to American Municipal Power, to allow stakeholders to evaluate the outputs of transmission providers' studies—i.e., the identified transmission needs—on their own, transmission providers must be required to provide the models.[3457] Furthermore, American Municipal Power argues, the Commission should require transmission providers to provide information on how assets

*Experience to Date and the Potential for Additional Customer Value* 26 (Apr. 2019)).

[3454] *See* Maryland Energy Administration Reply Comments at 2-3 (citations omitted).

[3455] California Water Initial Comments at 7-8 (citing *S. Cal. Edison*, Filing, App. XII, ER19-1553-000, at section 2.2 (filed July 2, 2020); *Pac. Gas & Elec. Co.*, Filing, App. IX, ER19-13-001, at section 3.2 (filed Mar. 31, 2020)).

[3456] American Municipal Power Initial Comments at 20-21.

[3457] *Id.* at 21.

have been prioritized for replacement, how the replacement versus maintenance decision is made, how assets rank relative to other assets on the system, and the system average values.[3458]

1616. Several commenters state that the NOPR proposal does not go far enough to protect customers' interests and suggest the addition of more process, more oversight, more monitoring (including establishing an independent transmission monitor), or more prudence reviews.[3459] According to PIOs, transmission providers have incentives to avoid independent transmission planning processes because local transmission projects are presumed to be prudent, avoid competition, and receive high rates of return. PIOs state that the Commission should reduce the rate of return for local transmission projects and issue a rule or policy statement that puts the burden of proof on transmission providers to demonstrate that the cost of a proposed transmission project is just and reasonable.[3460]

1617. Joint Consumer Advocates state that, while the NOPR proposal is an improvement, more needs to be done to address the imbalance between consumer

[3458] *Id.* at 22-23.

[3459] California Commission Initial Comments at 111-112 & n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25-29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23-24; OMS Initial Comments at 16-17; Pattern Energy Initial Comments at 31-34; Pine Gate Initial Comments at 49-50; PIOs Initial Comments at 51-52; PJM States Initial Comments at 4-6; TAPS Initial Comments at 61-62; US DOJ and FTC Initial Comments at 20-21.

[3460] PIOs Initial Comments at 52-53.

advocates and incumbent transmission owners. Therefore, Joint Consumer Advocates assert, the Commission should authorize the creation of an independent transmission monitor to evaluate the effective coordination of local transmission projects with more holistic transmission planning to identify the most efficient or cost-effective approach to meeting local, regional, and interregional transmission needs.[3461] Relatedly, California Commission and Colorado Consumer Advocates suggest that the Commission give independent transmission monitors the responsibility to evaluate stakeholder comments, independently analyze whether there are potentially more efficient and cost-effective alternative transmission solutions to meet identified transmission needs, and make a recommendation.[3462] Potomac Economics argues that the Commission's transparency goals likely cannot be met without an independent transmission monitor.[3463]

1618. Some commenters opine on whether the regional transmission planning process should assume an expanded role in reviewing or approving identified local transmission projects.[3464] In addition, NARUC recommends that the Commission allow the proposed stakeholder review process to apply to repair and replacement projects that do not expand

[3461] Joint Consumer Advocates Initial Comments at 26-29 (citations omitted).

[3462] California Commission Initial Comments at 111-112; Colorado Consumer Advocates Initial Comments at 31.

[3463] *See* Potomac Economics Initial Comments at 6.

[3464] *See* American Municipal Power Reply Comments at 3-7; California Commission Initial Comments at 108-110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60-61; Ohio Consumers Reply Comments at 17-18; PJM States Initial Comments at 6-7.

the capacity of the transmission system, or do so only incidentally, in particular those that are forecast to cost $3 million or more. NARUC asserts that, limiting the reforms to local transmission planning may exclude review of these projects, which currently comprise half of investor-owned utilities' transmission spending in the RTOs/ISOs. Further, NARUC urges the Commission to allow these projects, along with local transmission projects, to be reviewed and approved as part of the regional transmission planning process.[3465] California Commission agrees, stating that there should be more external scrutiny of such projects to reduce incumbent utilities' existing perverse incentive to overinvest in these types of projects due to their lack of external review.[3466]

1619. PJM States call on RTOs/ISOs to go beyond evaluating whether local transmission projects "do no harm" by actively taking a stance on such projects, discussing how this stance was reached, and by proposing transmission projects that may be the most cost-effective.[3467] However, PJM States ask the Commission to explicitly avoid impinging on state-jurisdictional processes.[3468]

1620. DC and MD Offices of People's Counsel and American Municipal Power assert that the remedy for the current lack of a requirement to incorporate or respond to stakeholder feedback in the local transmission planning process is an empowered

[3465] NARUC Initial Comments at 60-63 (citations omitted).

[3466] California Commission Initial Comments at 109-110 (citations omitted).

[3467] PJM States Initial Comments at 6-7 (citation omitted).

[3468] *Id.* at 7.

regional transmission planner that is independent and incorporates meaningful participation from all stakeholders beginning with the determination of any transmission needs through the project selection phase.[3469] Relatedly, Ohio Consumers state that the NOPR proposal leaves sole discretion in selection of transmission projects and the costs of the projects to transmission providers.[3470]

1621. However, some commenters defend the separation between local and regional transmission planning processes.[3471] For instance, AEP disagrees that transmission providers seek to build local transmission projects to circumvent the regional transmission planning process.[3472] According to AEP, local and regional transmission planning processes are not interchangeable because most local transmission facilities directly serve load and local utilities must address local needs when those needs are not addressed by a regional transmission facility in a cost-effective manner.[3473] Nevertheless, AEP states, there can be an effective and efficient intersection between local and regional transmission planning, citing PJM's open and transparent local transmission planning

[3469] American Municipal Power Reply Comments at 3-7 (citations omitted); DC and MD Offices of People's Counsel Initial Comments at 7.

[3470] Ohio Consumers Reply Comments at 18.

[3471] AEP Reply Comments at 6-7; MISO Reply Comments at 27; PG&E Reply Comments at 4-9; WIRES Initial Comments at 9.

[3472] AEP Reply Comments at 6-7 (citing AEE Initial Comments at 38; PIOs Initial Comments at 8-9; Resale Iowa Initial Comments at 7-8; US DOJ and FTC Initial Comments at 7).

[3473] *Id.* at 2-3.

process that requires coordination with the regional transmission planning process and in which PJM is an active participant.[3474] Similarly, WIRES states that there are good reasons for maintaining a distinction between regional and local transmission planning, noting that the regional transmission planning process is directed toward addressing certain reliability, economic criteria, and public policy initiatives, not the additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that are the focus of local transmission planning.[3475]

1622. Eversource states that, if the Commission decides to require a more prescriptive local transmission planning process, it should clarify that the process applies only to upgrades that are developed primarily to increase the capacity of the local transmission system, and not to upgrades that are incidental to state-jurisdictional distribution system planning or other unique local requirements.[3476]

1623. MISO defends the transparency of local transmission planning in MISO by stating that commenters who criticize existing local transmission planning processes "ignore the open, transparent process in effect, and fail to recognize the ongoing need for near-term

[3474] *Id.* at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0)).

[3475] WIRES Initial Comments at 9 (citing Charles River Associates, *The Value of Local Transmission Planning* 9, 13 (Dec. 2021), https://wiresgroup.com/wp-content/uploads/2021/12/Value-of-Local-Transmission-Planning-report-WIRES-CRA.pdf).

[3476] Eversource Initial Comments at 49.

planning."[3477] MISO states that local and regional transmission planning are complementary and that "near-, mid- and long-term planning work in concert."[3478] MISO contends that its existing process includes extensive stakeholder involvement that ensures that issues are identified and alternatives are considered.[3479]

1624. PG&E opposes comments in favor of removing the role of local transmission planning from local transmission owners, as well as requests to expand the NOPR proposal to apply to asset management projects. PG&E notes that California Commission has not provided any evidence that RTOs/ISOs are currently unable to adequately handle the regional and local transmission planning processes.[3480]

### 3. Commission Determination

1625. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to enhance the transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through the local transmission planning process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs. For each of these three categories of local transmission

[3477] MISO Reply Comments at 27 (citing PIOs Initial Comments at 32).

[3478] *Id.*

[3479] *Id.*

[3480] PG&E Reply Comments at 4-9 (citations omitted).

planning information, and as discussed further below, transmission providers must identify and publicly post the information identified below, then conduct publicly-noticed stakeholder meetings to provide an opportunity for comment on the information both before and after the stakeholder meetings, as part of the regional transmission planning process. In response to comments from PG&E,[3481] we clarify that this requirement applies only to local transmission planning that is within the scope of Order No. 890 and is therefore already subject to Order No. 890 transparency requirements. As such, this requirement does not apply to asset management projects.[3482] However, nothing in this final rule prevents transmission providers from choosing to apply these requirements to asset management projects.

1626. In complying with this requirement, transmission providers must establish an iterative process that ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process. To provide the needed transparency and opportunities for stakeholder participation, we require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings per regional transmission planning cycle concerning the local transmission planning process of each

[3481] PG&E Initial Comments at 17 (citing *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec.*, 164 FERC ¶ 61,161 at P 66).

[3482] *See S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at PP 30-40; *Cal. Pub. Utils. Comm'n v. Pac. Gas. & Elec. Co.*, 164 FERC ¶ 61,161 at PP 65-74 (finding that Order No. 890's local transmission planning requirements do not apply to asset management projects that do not increase capacity or do so incidentally).

transmission provider that is a member of the transmission planning region before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1627. Specifically, we adopt the NOPR proposal to require that, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, no fewer than 25 calendar days after the Needs Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). Additionally, we require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.

1628. In addition to these requirements, we modify the NOPR proposal to also require transmission providers to publicly post the meeting materials no fewer than five calendar days prior to each of the three publicly-noticed stakeholder meetings to allow time for stakeholders to review materials in advance of each meeting. Also, we require that transmission providers allow for a period of no fewer than 25 calendar days following the Solutions Meeting to review and consider stakeholder feedback on the local transmission solutions identified to meet the local transmission needs before the local transmission plan can be incorporated in the transmission planning region's planning models. Requiring this minimum 25 calendar day period is consistent with Order No. 1000, where the Commission stated that the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.[3483] Lastly, we require that transmission providers must respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate in these three required stakeholder meetings.

1629. We find that establishing a standard baseline of transparency into transmission providers' local transmission planning processes will ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning assumptions, needs, and solutions that are used as inputs to the regional transmission planning process.

[3483] Order No. 1000, 136 FERC ¶ 61,051 at P 153 (citing Order No. 890, 118 FERC ¶ 61,119 at P 454).

We expect that this additional transparency will help reduce the possibility that transmission providers will develop local transmission facilities without adequately considering whether there is a more efficient or cost-effective regional transmission solution that could address their local transmission needs. This additional transparency will enable transmission providers to satisfy their requirements for regional transmission planning under Order No. 1000.[3484]

1630. We believe that the local transmission planning information provided pursuant to the enhanced transparency requirements that we adopt in this final rule will better facilitate the identification through the regional transmission planning process of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities.[3485] Specifically, transmission providers' local transmission planning information will be subject to review and comment by stakeholders that may provide additional information or identify considerations that could inform the criteria, models, and assumptions used in local transmission planning, the identification of local transmission needs, and the identification of transmission facilities to address those local transmission needs. Because local transmission planning information serves as an input to the regional transmission planning process, these improvements will, in turn, facilitate the identification of more efficient or cost-effective transmission facilities in the regional

[3484] *Id.* PP 78-84.

[3485] NOPR, 179 FERC ¶ 61,028 at P 402.

transmission planning process, resulting in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.

1631. With respect to the comments from National and State Conservation Organizations and WE ACT[3486] that robust input from affected and overburdened communities in the local transmission planning process is important, we believe that the added transparency requirements that require transmission providers to identify and publicly post the information and then conduct stakeholder meetings as part of the regional transmission planning process, provides an opportunity for interested parties to engage and comment on the information.

1632. With regard to commenters that suggest that the additional transparency requirements proposed in the NOPR will not be effective because they do not go far enough in making changes to local transmission planning processes,[3487] we find that the enhanced transparency requirements that we adopt in this final rule are specifically designed to provide needed transparency to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. In addition, we find that other commenters' suggestions for changes to local transmission planning processes were not proposed in the NOPR and therefore are outside the scope of this proceeding. We conclude that the replacement rate set forth herein is just and reasonable

[3486] National and State Conservation Organizations Initial Comments at 2; WE ACT Initial Comments at 5-6.

[3487] *See* American Municipal Power Initial Comments at 17-18; Ohio Commission Federal Advocate Initial Comments at 19-20.

and addresses the deficiencies identified herein.[3488] We note that the Commission continues to examine a suite of related issues in its Transmission Planning and Cost Management proceeding.[3489]

1633. In response to American Municipal Power's assertion that the PJM Attachment M-3 process has increased the problem of planning based on individual transmission owners' criteria and the balkanization of the transmission planning process,[3490] we find that American Municipal Power has not persuasively explained why these concerns are the result of increasing the *transparency* of local transmission planning, rather than other factors associated with the PJM Attachment M-3 process. Based on the record before us, we do not expect that requiring enhanced transparency in local transmission planning, in the manner directed in this final rule, will result in greater incentives for transmission providers to develop local transmission facilities in lieu of regional transmission facilities. Instead, we expect that additional opportunities for stakeholder review of and comment on local transmission planning inputs into the regional transmission planning process will help to facilitate the identification of regional transmission facilities that are more efficient or cost-effective compared to transmission facilities identified in the local transmission planning process.

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[3488] *See New York v. FERC*, 535 U.S.at 26-28 (upholding Commission's decision not to assert jurisdiction over bundled retail transmission).

[3489] *See* Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22-8-000 (Apr. 21, 2022).

[3490] American Municipal Power Initial Comments at 17.

1634. We disagree with commenters that state that the NOPR proposal is not needed in their transmission planning region because their local transmission planning process is already sufficiently transparent.[3491] The reforms that we adopt here are necessary to ensure just and reasonable rates, as more fully explained above. Additionally, we believe that these reforms to enhance the transparency of local transmission planning inputs into the regional transmission planning process are necessary to ensure that interested stakeholders have an opportunity to meaningfully participate in the review of the local transmission planning assumptions, needs, and solutions before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1635. Similarly, we disagree with commenters that oppose the proposal because it may interfere with existing transmission planning processes.[3492] As we explain above, the enhanced transparency and opportunities for stakeholder participation are needed to ensure just and reasonable Commission-jurisdictional rates. Although we appreciate that there may be differences in how transmission providers currently conduct local

[3491] APS Initial Comments at 12-13; Avangrid Initial Comments at 13-15; CAISO Initial Comments at 46-50; Dominion Initial Comments at 69-70; Eversource Initial Comments at 46-49; MISO Initial Comments at 84-86; MISO TOs Initial Comments at 29-31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16-18.

[3492] Avangrid Initial Comments at 13; CAISO Initial Comments at 7, 47; Dominion Initial Comments at 70; Eversource Initial Comments at 47-48; MISO Initial Comments at 86; PG&E Initial Comments at 17-18; PPL Initial Comments at 36; Xcel Initial Comments at 16-17.

transmission planning, we believe that the standard baseline of transparency established by the requirements adopted in this final rule is needed to ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning inputs that go into the regional transmission planning process and to ensure that the regional transmission planning process can identify regional transmission facilities that address transmission needs more efficiently or cost-effectively than local transmission facilities. The fact that transmission providers may need to adjust their existing processes to comply with these requirements is not a sufficient reason for the Commission to decline to adopt them.

1636. We also disagree with commenters that argue that the proposal is too prescriptive.[3493] We believe that these requirements strike a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. In fact, experience with the PJM Attachment M-3 process, which includes similar requirements to those adopted in this final rule, provides evidence that it is possible to satisfy these requirements with a process that allows transmission providers to produce their local transmission plans on a

[3493] *See* Avangrid Initial Comments at 13-15; EEI Initial Comments at 40; Eversource Initial Comments at 47-48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84-86; MISO TOs Initial Comments at 29-31; National Grid Initial Comments at 39-41; New York TOs Initial Comments at 7, 16-17; Xcel Initial Comments at 17.

timely basis.[3494] In response to National Grid's concern that the NOPR proposal would impose a new requirement to integrate their local transmission planning with regional transmission planning,[3495] the final rule imposes no new requirements beyond the three meetings and associated opportunities for comment described above. We believe that these requirements add only a small but manageable burden for transmission providers, which is outweighed by the transparency benefits that would accrue to stakeholders participating in the local and regional transmission planning processes.

1637. With respect to the comments of APS and National Grid that local transmission planning cycles might be delayed by the new transparency requirements,[3496] we reiterate that the final rule strikes a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. We believe that, even with the additional requirements that we establish here, it is possible for transmission providers to produce local transmission plans within a 12-month period, especially given that when scheduling the three required meetings, transmission providers need not leave more than 25 calendar days between each meeting. The experience of PJM TOs, whose local transmission

[3494] *See* Indicated PJM TOs Initial Comments at 42-43 (citations omitted).

[3495] National Grid Initial Comments at 39-40.

[3496] APS Initial Comments at 13; National Grid Initial Comments at 39-40.

planning processes are subject to similar requirements, demonstrates that it is possible to satisfy these requirements in a timely manner.[3497]

### a. Specific Stakeholder Meeting Requirements

1638. We address in this section the requirements specific to the implementation details associated with the three publicly-noticed stakeholder meetings that transmission providers are required to conduct: the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, that were discussed above. We believe that these requirements strike a reasonable balance between providing adequate time to allow interested stakeholders to review and comment on local transmission planning inputs that are used in regional transmission planning and allowing the efficient and timely execution of the local transmission planning process. In our view, allowing transmission providers to limit the length of time between the three required meetings accomplishes this balance.

1639. With respect to commenters who argue that a minimum of 25 calendar days between publicly-noticed stakeholder meetings is too short,[3498] we disagree. The minimum period between stakeholder meetings is just that, a minimum, and we expect that transmission providers and their stakeholders will, in practice, implement a schedule for the required stakeholder meetings that best meets the needs of their transmission planning region. However, we find that a minimum of less than 25 calendar days

[3497] Exelon Initial Comments at 3-4, 51-52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0)); Indicated PJM TOs Initial Comments at 42-43.

[3498] American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; TAPS Initial Comments at 6, 62.

between stakeholder meetings would not allow stakeholders to participate in a meaningful way, and we therefore adopt this minimum period as an appropriate baseline for providing stakeholders with a meaningful opportunity to review and comment on local transmission planning inputs that are used in regional transmission planning. And, in fact, at least some transmission providers have adopted this minimum duration between stakeholder meetings.[3499]

1640. We clarify that transmission providers are required to provide information at least five calendar days prior to each of the three publicly-noticed stakeholder meetings. As stated above, transmission providers must publicly notice each meeting and publicly post all materials for stakeholder review during the three meetings and provide opportunities for stakeholders to submit comments before and after each meeting. We believe that providing this information at least five calendar days prior to each of the three stakeholder meetings strikes a balance between giving stakeholders meaningful opportunity to review the meeting materials ahead of each meeting and limiting the burden to transmission providers in posting the materials ahead of time. Furthermore, the information that we require transmission providers to share is information that they use in

[3499] See PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0.), which, briefly, refers to the additional transparency and stakeholder input rules around transmission facilities that are not eligible for selection, but, though classified as local transmission facilities, nonetheless impact the identification and selection of regional transmission facilities. *See also Duke Energy Carolinas, LLC*, 186 FERC ¶ 61,178, at PP 13, 27 (2024) (accepting Duke's OATT revisions to adopt a stakeholder meeting process that includes an Assumptions Meeting, Needs Meeting, and Solutions Meeting, each no fewer than 25 calendar days apart).

their local transmission planning processes and, thus, is information that they generally already possess.

1641. We disagree with commenters that argue that three separate publicly-noticed stakeholder meetings are unnecessary and will increase workload without any benefit, or that a single meeting would address the Commission's transparency concerns more efficiently, or request that the Commission not dictate the number of stakeholder meetings.[3500] We note that Indicated PJM TOs state that the PJM Attachment M-3 process has the benefit of avoiding duplication of projects between local and regional transmission planning processes.[3501] We also disagree with MISO's argument that we should allow each transmission planning region to have complete discretion over the timing of the meetings, as well as the specific information to be covered at the meetings.[3502] While we allow flexibility in certain aspects of the transmission planning processes, we find that the requirement to hold three separate stakeholder meetings a minimum of 25 calendar days apart and prescribing the type of information that transmission providers must share at each meeting is necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. We balance the increased burden imposed on transmission

[3500] Dominion Initial Comments at 68; Eversource Initial Comments at 47-48; NESCOE Initial Comments at 78; Xcel Initial Comments at 17.

[3501] Indicated PJM TOs Initial Comments at 42.

[3502] MISO Initial Comments at 84.

providers with the benefits associated with providing increased information and opportunities for stakeholder review of and comment on the local transmission planning inputs that are used in the regional transmission planning process. In addition, as discussed above, we believe that these reforms will reduce after-the-fact disputes and will help facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities. As a result, the incremental burden of having to hold three stakeholder meetings to share this information and to consider input from stakeholders in response to this information is outweighed by the benefits that the increased transparency will provide.

1642. We also find unconvincing Eversource's assertion that the reforms will not work where there is not a precisely defined regional transmission planning cycle, such as is the case in ISO-NE.[3503] The requirement to hold three publicly-noticed stakeholder meetings is triggered by the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process and is not tied to a particular transmission planning cycle. Nevertheless, we recognize that these reforms may require transmission providers to propose adjustments to their existing processes. But as explained above, we believe that the need for transparency and stakeholder involvement requires these changes to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

[3503] Eversource Initial Comments at 47.

1643. In response to TAPS' request that transmission providers be required to post their transmission planning criteria, models, and assumptions,[3504] we reiterate that transmission providers must provide this information as part of the Assumptions Meeting. We further note that the requirement for transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission systems is an existing requirement of Order No. 890. This information must enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.[3505] The Commission recognized in Order No. 890 that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities and, therefore, requires that transmission providers have mechanisms in place in their OATTs to manage confidentiality and CEII concerns, such as confidentiality agreements and password-protected access to information.[3506] However, we reiterate that information must be disclosed, under applicable confidentiality provisions, if the information is needed to participate in the transmission planning process and to replicate transmission planning studies, which necessarily includes access to the models that underlie transmission planning processes.

[3504] TAPS Initial Comments at 61.

[3505] Order No. 890, 118 FERC ¶ 61,119 at P 471.

[3506] *Id.* P 460.

1644. We decline to require, as requested by American Municipal Power and TAPS, that transmission providers hold two Solutions Meetings.[3507] While a transmission provider may determine that additional stakeholder meetings are appropriate or necessary, we only require transmission providers to conduct the three publicly-noticed stakeholder meetings discussed above. However, there is nothing in this final rule that prohibits transmission providers from holding additional meetings, beyond those required here. We find NRG's request that the Commission require the local transmission planning process include an estimated rate impact for each year if the local transmission plan were to be executed to be beyond the scope of the proposal, although transmission providers may choose to provide this information outside of the context of this rule.

1645. In response to commenters that request that the Commission require transmission providers to respond to all comments and questions submitted by stakeholders in the local transmission planning process,[3508] we clarify that such a requirement could be too prescriptive in certain circumstances and thus we decline to set a bright-line rule that transmission providers must respond to each and every question or comment received through the stakeholder process. Nevertheless, we require transmission providers to respond to questions or comments in a manner that allows stakeholders to meaningfully

[3507] American Municipal Power Initial Comments at 24-25; TAPS Initial Comments at 62 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

[3508] *See* American Municipal Power Initial Comments at 18-19; California Commission Initial Comments at 112-113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky Commission Chair Chandler Initial Comments at 21-22; Northwest and Intermountain Initial Comments at 20-21; TAPS Initial Comments at 62.

participate in these stakeholder meetings. For example, in the context of live discussions in any of the three required publicly-noticed stakeholder meetings, we expect transmission providers to offer stakeholders an opportunity to speak, engage, and ask questions, as well as receive reasonable responses at the meeting consistent with meaningful participation. Overall, we encourage transmission providers to be as responsive as possible to stakeholder comments and questions. However, we recognize that not all comments or questions require an answer or a response, or that some responses may be unduly burdensome to the transmission provider. To the extent that there are disagreements, we note that stakeholders have dispute resolution procedures available, as required under Order No. 890.[3509] Some commenters have asked the Commission to require transmission providers to provide "additional clarity" regarding how alternatives were developed and why they were not selected during the Solutions Meeting, as requested by American Municipal Power.[3510] In balancing the need for transparency and the burden for transmission providers, we find that a meaningful participation standard regarding sharing of local transmission planning inputs that are used in the regional transmission planning process that are established by the Commission is reasonable.

[3509] Order No. 890, 118 FERC ¶ 61,119 at PP 501-503.

[3510] American Municipal Power Initial Comments at 24-25.

1646. In addition, in response to TAPS' request regarding disputes over local transmission planning inputs,[3511] we clarify that where disputes arise regarding transparency into the local transmission planning inputs, the transmission provider's existing dispute resolution process, as established in Order No. 890, governing the transmission planning process should be used.[3512] Further, affected entities retain any rights that they may have under FPA section 206 to file complaints with the Commission.

**b. Additional Issues**

1647. As it pertains to PPL's request that the Commission clarify that confidential or sensitive information will be protected,[3513] we clarify that transmission providers must continue to apply the same safeguards to protect sensitive or critical information, such as confidentiality agreements and password protected access to information, as the Commission required in Order No. 890 and that transmission providers currently apply to the sharing of transmission planning information to protect against inappropriate disclosure of confidential information.[3514]

1648. Many commenters suggest additional reforms because these commenters find the NOPR proposal insufficient. These suggested reforms include additional measures to

[3511] TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501-503).

[3512] Order No. 890, 118 FERC ¶ 61,119 at P 501.

[3513] PPL Initial Comments at 36.

[3514] Order No. 890, 118 FERC ¶ 61,119 at PP 460, 471.

protect customers' interests and additional process, more oversight, more monitoring (including establishing an independent transmission monitor), or prudence reviews;[3515] requiring RTOs/ISOs to assume a larger role in reviewing or approving identified local transmission projects;[3516] requiring a performance-based method of enhancing transparency in local transmission planning processes;[3517] and requiring transmission providers to make available additional transmission planning data,[3518] improve formatting of transmission planning inputs,[3519] or otherwise coordinate with load-serving entities to transfer data and information.[3520] The Commission did not make such proposals in the NOPR and, as a result, we find these requests to be beyond the scope of this proceeding and decline to adopt them. We note, however, that several of these issues may be

[3515] California Commission Initial Comments at 111-112 &n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25-29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23-24; OMS Initial Comments at 16-17; Pattern Energy Initial Comments at 31-34; Pine Gate Initial Comments at 49-50; PIOs Initial Comments at 51-52; PJM States Initial Comments at 4-6; TAPS Initial Comments at 61-62; US DOJ and FTC Initial Comments at 20-21.

[3516] *See* American Municipal Power Reply Comments at 3-7; California Commission Initial Comments at 108-110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60-61; Ohio Consumers Reply Comments at 17-18; PJM States Initial Comments at 6-7.

[3517] Vermont Electric and Vermont Transco Initial Comments at 5.

[3518] American Municipal Power Initial Comments at 21-24 (citations omitted); Pattern Energy Initial Comments at 30-34.

[3519] Joint Consumer Advocates Initial Comments at 21-22.

[3520] Certain TDUs Initial Comments at 18.

examined in the Commission's ongoing Transmission Planning and Cost Management proceeding.[3521]

### C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

#### 1. Eligibility

##### a. NOPR Proposal

1649. The Commission proposed to require, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. The Commission proposed to define "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[3522]

1650. The Commission described the process under this proposed reform as entailing the following steps. First, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider would submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if a right-sized

[3521] Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22-8-000 (Apr. 21, 2022).

[3522] NOPR, 179 FERC ¶ 61,028 at P 403.

replacement transmission facility is identified as a potential solution to a Long-Term Regional Transmission Planning need, that right-sized replacement transmission facility would be evaluated in the same manner as any other proposed transmission facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets all of the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution to a transmission need identified through Long-Term Regional Transmission Planning, then the right-sized replacement transmission facility may be selected in the regional transmission plan for purposes of cost allocation.[3523]

1651. The Commission explained that nothing in the reforms proposed in the NOPR would alter a transmission provider's existing rights and responsibilities under existing laws with respect to maintaining, and when necessary, replacing, existing transmission facilities. Further, as the Commission explained, it may be possible for an in-kind replacement transmission facility to be *included* in the regional transmission plan for informational purposes, but not be *selected*.[3524]

[3523] *Id.* P 407.

[3524] *Id.* PP 412-413.

**b. Comments**

1652. Several commenters support the NOPR's proposals related to right-sizing.[3525] ITC states that the NOPR proposal will result in better use of existing facilities and rights-of-way to quickly deliver additional transmission capacity. ITC maintains that increasing the transfer capability of existing transmission facilities lessens the impacts on communities and other land users, in addition to raising fewer environmental considerations.[3526] ITC adds that right-sizing will form a critical input to transmission planning and state siting processes by encouraging designs that meet future needs.[3527]

1653. OMS also supports the Commission's proposed realignment of incentives to ensure that transmission providers are not incentivized through right-sizing to rebuild and replace facilities before considering other opportunities, instead providing a level playing field to consider other solutions.[3528] PJM states that right-sizing allows transmission owners to meet their reliability obligations while transmission providers have the

[3525] ACORE Initial Comments at 19; Ameren Initial Comments at 46-47; APPA Initial Comments at 48; California Energy Commission Initial Comments at 3; CTC Global Initial Comments at 18; ELCON Initial Comments at 27; Evergreen Action Initial Comments at 4; ITC Initial Comments at 45; ITC Reply Comments at 29; New York Commission and NYSERDA Initial Comments at 15; Northwest and Intermountain Initial Comments at 21; OMS Initial Comments at 17; PJM Initial Comments at 9, 121-122; SEIA Initial Comments at 26; US Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

[3526] ITC Initial Comments at 45.

[3527] ITC Reply Comments at 29.

[3528] OMS Initial Comments at 17.

opportunity to find more efficient solutions to regional transmission needs and avoid duplicative transmission development.[3529]

1654. AEP supports applying the right-sizing evaluation to transmission facilities operating at or above 230 kV because replacement transmission facilities that will operate at or above 230 kV are most susceptible to modification to meet long-term regional transmission needs.[3530] PG&E also supports the proposed voltage threshold, claiming that the inclusion of lower voltage transmission projects would substantially expand the number of projects that would need to be evaluated for right-sizing while offering little benefit. Specifically, PG&E contends that lower voltage transmission projects are typically needed for specific, local purposes and thus do not need to be right-sized, and that a requirement that they be evaluated for right-sizing would burden the RTO/ISO process.[3531]

1655. APPA supports the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.[3532] AEP also supports a 10-year horizon for identifying in-kind replacements, so long as the list of transmission facilities is non-binding and may be

[3529] PJM Initial Comments at 121-122 (citing NOPR, 179 FERC ¶ 61,028 at PP 406, 408).

[3530] AEP Initial Comments at 44-45 (citing NOPR, 179 FERC ¶ 61,028 at P 406).

[3531] PG&E Reply Comments at 14-15.

[3532] APPA Initial Comments at 48 (citing NOPR, 179 FERC ¶ 61,028 at P 403).

modified as transmission projects mature or expected facility lives can be extended through other means.[3533]

1656. CAISO requests that the Commission clarify that the NOPR does not preclude it from continuing to consider modifications to in-kind replacements for transmission facilities below 230 kV in its annual transmission planning process.[3534]

1657. Several commenters support the NOPR's right-sizing proposal but with certain conditions.[3535] Further, some commenters argue that if the Commission adopts the NOPR proposal, the Commission must ensure that the proposal does not disrupt or impair existing local transmission planning processes.[3536] For example, AEP asserts that the Commission must ensure that the NOPR proposal does not undermine the local

[3533] AEP Initial Comments at 44-45.

[3534] CAISO Initial Comments at 50.

[3535] ACEG Initial Comments at 8-9, 56-58; AEP Initial Comments at 43-44; Avangrid Initial Comments at 15-16; Breakthrough Energy Initial Comments at 3, 19; California Commission Initial Comments at 113-118; California Water Initial Comments at 8-9; Clean Energy Associations Initial Comments at 36-37; EEI Initial Comments at 41; Eversource Initial Comments at 52; Exelon Initial Comments at 3, 51; ISO-NE Initial Comments at 39; MISO Initial Comments at 87; NARUC Initial Comments at 58-59, 63-64; NESCOE Initial Comments at 21-22, 78-79; NESCOE Reply Comments at 6-8; NESCOE Supplemental Comments at 7-9; NextEra Initial Comments at 66-67; NRECA Initial Comments at 67; NYISO Initial Comments at 58-60; PG&E Initial Comments at 12-14; Pine Gate Initial Comments at 46-50; PIOs Initial Comments at 57-58; State Agencies Initial Comments at 20-22; TAPS Initial Comments at 6-7, 64; VEIR Initial Comments at 6; Vermont State Entities Initial Comments at 11-13; WIRES Initial Comments at 10.

[3536] *See* AEP Initial Comments at 43-44; CAISO Initial Comments at 50; Mississippi Commission Initial Comments at 30-31; Mississippi Commission Reply Comments at 9-10; PJM States Initial Comments at 8; WIRES Initial Comments at 10.

transmission planning process or transmission owners' rights to build transmission projects that address local needs.[3537] Mississippi Commission asserts that, if the NOPR proposal is adopted, the ultimate decision as to which local transmission project is constructed must rest with the states that have transmission siting authority and the incumbent transmission owners.[3538] PJM States ask for clarification on how the NOPR proposal will interact with existing processes, noting that in PJM, any need that appears both on a five-year end-of-life needs list and in PJM's regional transmission plan is eligible for competition (as compared to the NOPR proposal, under which transmission projects to address 10-year-out needs would not be eligible for competition).[3539]

1658. NESCOE states that ISO-NE lacks the clear standards required to support right-sizing, citing an Eversource transmission project that improved grid reliability but was ineligible for regional cost allocation because it did not meet the standards to qualify as a right-sized project.[3540] NESCOE argues that more transparency into the right-sizing processes is necessary to ensure that the results are disciplined, cost-conscious investments.[3541]

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[3537] AEP Initial Comments at 43-44.

[3538] Mississippi Commission Initial Comments at 30-31.

[3539] PJM States Initial Comments at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M-3 (1.0.0), § (d)1.iii).

[3540] NESCOE Reply Comments at 6-8.

[3541] NESCO Supplemental Comments at 9.

1659. Several commenters oppose the NOPR's right-sizing proposal.[3542] Competition Coalition asserts that the NOPR proposal would result in over-building the transmission system now for speculative future transmission needs, leaving customers with the bill for any stranded costs.[3543] Louisiana Commission claims that the NOPR right-sizing proposal should not be adopted because it will intrude on its retail authority.[3544]

1660. Other commenters argue that the proposed 230 kV threshold is inappropriate.[3545] For example, Avangrid contends that it is overly prescriptive and does not reflect regional conditions, needs, and stakeholder interests.[3546] Avangrid states that, in ISO-NE, a 230 kV threshold would result in in-kind replacement of lower voltage transmission facilities rather than right-sizing facilities to most efficiently meet transmission needs identified through Long-Term Regional Transmission Planning.

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[3542] Anbaric Initial Comments at 7; Competition Coalition Initial Comments at 62-63; DC and MD Offices of People's Counsel Initial Comments at 47-48; Idaho Power Initial Comments at 13; Kentucky Commission Chair Chandler Initial Comments at 16-19; Louisiana Commission Initial Comments at 39; LS Power Initial Comments at 135-136, 138, 141-142, 145-146; Massachusetts Attorney General Initial Comments at 51-52; Ohio Consumers Initial Comments at 23; Resale Iowa Initial Comments at 8-9.

[3543] Competition Coalition Initial Comments at 62-63.

[3544] Louisiana Commission Initial Comments at 39.

[3545] Avangrid Initial Comments at 15-16; California Commission Initial Comments at 117-118; Kentucky Commission Chair Chandler Initial Comments at 18-19; New York TOs Initial Comments at 17-18; NYISO Initial Comments at 59; Ohio Consumers Initial Comments at 23; PJM Initial Comments at 9, 121-122; State Agencies Initial Comments at 20-21; TAPS Initial Comments at 6, 66.

[3546] Avangrid Initial Comments at 15-16.

1661. Kentucky Commission Chair Chandler argues that 200 kV or 230 kV are no longer adequate rules of thumb to delineate local versus regional transmission facilities, as transmission facilities that may have been formerly classified as local are likely to be regional in the future. Rather, Kentucky Commission Chair Chandler states that transmission facilities rated between 100 kV and 200 kV will play a greater role in the regional delivery of energy.[3547] Ohio Consumers argue that the Commission should lower the threshold to 69 kV because many end-of-life transmission facilities in the PJM transmission planning process are expensive rebuilds of transmission facilities that are rated below 230 kV.[3548] TAPS argues that excluding lower voltage facilities prevents transmission planning regions from being able to consider more efficient and cost-effective alternatives.[3549]

1662. LS Power asserts that the Commission should not limit its right-sizing proposal to facilities above 230 kV and that such reforms should apply to lower voltage transmission facilities as well.[3550] Specifically, LS Power argues that transmission facilities that

[3547] Kentucky Commission Chair Chandler Initial Comments at 18-19.

[3548] Ohio Consumers Initial Comments at 23.

[3549] TAPS Initial Comments at 6, 66.

[3550] *See* LS Power Partial Reply Comments at 61-64 (citing California Commission Initial Comments at 117; Eversource Initial Comments at 38; ISO-NE Initial Comments at 39; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 142; NARUC Initial Comments at 64; Ohio Consumers Initial Comments at 23; State Agencies Initial Comments at 21).

operate at or above 100 kV (and sometimes facilities operating at a lower voltage) are regional in nature and should be subject to exclusively regional transmission planning.[3551]

1663. Shell states that the Commission should consider lowering the proposed voltage threshold to 115 kV, but notes that doing so may include lower voltage facilities that predominantly serve sub-transmission, wholesale distribution, or retail distribution purposes and have only local benefits.[3552] To ensure that the costs of sub-transmission, wholesale distribution, or retail distribution facilities are not rolled into transmission rates, Shell argues that the Commission should reexamine its standards for rolling the costs of transmission facilities into rates, its application of the Seven Factor test for functionalizing facilities as distribution or transmission, and its *Mansfield* integration analysis.[3553] Western Utilities contend that the Commission should not adopt Shell's proposal to lower the right-sizing threshold to 115 kV because whether or not a facility is a transmission facility is a fact-specific question.[3554]

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[3551] *Id.* at 64.

[3552] Shell Reply Comments at 10 (citing Shell Initial Comments at 34).

[3553] Shell Initial Comments at 34-36; Shell Reply Comments at 10-11 (citing *Commonwealth Edison Co.*, 167 FERC ¶ 61,173, at P 12 n.23 (2019); *Buckeye Power, Inc. v. Am. Transmission Sys. Inc.*, Opinion No. 533, 148 FERC ¶ 61,174, at PP 12, 41, 69 (2014), *order on reh'g*, 151 FERC ¶ 61,091 (2015); *Mansfield Mun. Elec. Dep't v. New England Power Co.*, Opinion No. 454, 97 FERC ¶ 61,134 (2001), *order on reh'g*, Opinion No. 454-A, 98 FERC ¶ 61,115 (2002)).

[3554] *See* Western Utilities Reply Comments at 2 (citing Shell Initial Comments at 34-35).

1664. Pine Gate recommends against the Commission adopting the bright-line voltage threshold specified in the NOPR, but urges the Commission require each transmission provider to: (1) list and evaluate existing transmission facilities operating at or above 230 kV that it owns and estimates may need to be replaced with a new in-kind transmission facility over the next 10 years; and (2) establish criteria by which it will identify lower-voltage facilities that could potentially be right-sized through Long-Term Regional Transmission Planning.[3555] Relatedly, WIRES states that the Commission should either: (1) clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities at a lower voltage threshold if existing transmission planning processes already do so; or (2) provide flexibility for transmission planning regions to justify the use of a different voltage threshold.[3556]

1665. Some commenters oppose the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.[3557] Exelon states that the Commission's proposed requirement to have a 10-year time horizon for identifying a list of potential end-of-useful life needs is infeasible and inconsistent with utility practices. Specifically, Exelon states that it does not develop a concrete plan for transmission projects to meet end-of-useful life needs five years in advance – let alone 10 years – but instead maintains a "dynamic list" of older

[3555] Pine Gate Initial Comments at 48.

[3556] WIRES Initial Comments at 10.

[3557] Eversource Initial Comments at 53; Exelon Initial Comments at 54-55; Indicated PJM TOs Initial Comments at 46-47; Kentucky Commission Chair Chandler Initial Comments at 17-18; SERTP Sponsors Initial Comments at 38-39.

assets, the condition of which is evaluated on a rolling basis, based on numerous factors such as equipment inspection and testing, maintenance history, historical performance, obsolescence, operational experience, asset criticality, equipment failure data, and age.[3558]

1666. Some commenters argue that the NOPR proposal is not applicable to their transmission planning regions or that their existing processes are sufficient.[3559] For example, CAISO explains that it plans all upgrades and expansions of transmission facilities under its operational control, which include transmission facilities at all voltage levels and at all locations on the system. Further, CAISO states that, if an asset management, maintenance, or in-kind replacement project can be expanded or modified to address a CAISO-identified transmission need in a local area (or system wide), CAISO can order such expansion or modification in its regional transmission planning process.[3560]

[3558] Exelon Initial Comments at 54-55 (*Exelon Utilities Asset Management Guidelines and Practices* 3 (Nov. 18, 2020), https://pjm.com/-/media/committees-groups/committees/srrtep-ma/2020/20201216/20201216-exelon-final-end-eol-guidelines.ashx).

[3559] CAISO Initial Comments at 47-48; Dominion Initial Comments at 69-70, 72; Duke Initial Comments at 46; MISO Initial Comments at 87-88; MISO Reply Comments at 28; New York TOs Initial Comments at 17; SERTP Sponsors Initial Comments at 38-39; SPP Initial Comments at 34-35.

[3560] CAISO Initial Comments at 47-48 (citing CAISO ANOPR Initial Comments at 73; *Cal. Pub. Utils. Comm'n v. Pac. Gas and Elec. Co.*, 164 FERC ¶ 61,161 at PP 35-37, 69).

1667. MISO asserts that right-sizing is fundamental to transmission planning and should always be considered as part of Good Utility Practice, but that right-sizing decisions are best made on a case-by-case basis, as there are both quantitative and qualitative considerations that must be taken into account.[3561] MISO contends that its existing local transmission planning achieves the Commission's objectives, as the MISO process provides for right-sizing where MISO selects the most robust solution. Accordingly, MISO states that, for its footprint, no changes are needed.[3562]

1668. SERTP Sponsors argue that replacement decisions for particular equipment may be triggered more by the conditions of a particular facility than its age. SERTP Sponsors argue that a process like right-sizing already occurs in SERTP's regional transmission planning, which requires that the SERTP Sponsors affirmatively look to determine if there are regional transmission alternatives that would be more efficient or cost-effective than the transmission solutions otherwise included in SERTP's regional transmission plan, including projects to replace aging infrastructure.[3563]

1669. Several commenters argue that the Commission should adopt alternative or additional requirements that apply when transmission providers evaluate transmission facilities for right-sizing.[3564] For example, Ameren requests that the Commission require

[3561] MISO Initial Comments at 87.

[3562] MISO Reply Comments at 28 (citing OMS Initial Comments at 15-17).

[3563] SERTP Sponsors Initial Comments at 38-39 (citations omitted).

[3564] ACEG Initial Comments at 58; Ameren Initial Comments at 46-47; American Municipal Power Initial Comments at 27; Breakthrough Energy Initial Comments at 18-

transmission providers to consider the following additional criteria when determining whether a transmission facility is eligible for right-sizing: (1) whether a transmission line is in the top 10 limiting elements on an import or transfer study; (2) whether a line has shown up as a real-time binding constraint in the last two years; or (3) whether a line shows up as a binding constraint in future security constrained economic dispatch simulations.[3565] California Energy Commission argues that the Commission should develop a definition of "right-sizing," possibly tied to a specified planning reserve margin as well as an expected level of demand growth.[3566] Furthermore, ACEG and PG&E both request that the Commission consider the use of existing transmission facility rights-of-way as an eligibility threshold for potentially right-sized replacement transmission facilities.[3567]

1670. Eversource asserts that it would be more efficient to evaluate potential right-sizing: (1) through a review of the transmission facilities that could be upgraded to address identified long-term transmission needs, including an evaluation of whether an

19; California Energy Commission Initial Comments at 3; Competition Coalition Initial Comments at 68; CTC Global Initial Comments at 18; Eversource Initial Comments at 53; Exelon Initial Comments at 56-58; Grid United Initial Comments at 3-4; Pennsylvania Commission Initial Comments at 21; PG&E Initial Comments at 13-14; Pine Gate Initial Comments at 48; PIOs Initial Comments at 57-58; PJM Initial Comments at 9, 121-122; PPL Initial Comments at 36-37; Shell Initial Comments at 34.

[3565] Ameren Initial Comments at 46-47.

[3566] California Energy Commission Initial Comments at 3.

[3567] ACEG Initial Comments at 57-58; PG&E Initial Comments at 13.

in-kind replacement is likely to occur during the planning horizon; or (2) through transmission owner identification of right-sizing options that align with needs identified in the longer-term study as they perform their normal asset condition projects.[3568]

1671. Entergy asserts that the Commission should clarify that storm-hardening transmission projects are not subject to a right-sizing requirement because it would add complications and delays to the right-sizing process.[3569] Pennsylvania Commission argues that a transmission facility should not be right-sized if its total cost exceeds the total cost of the local transmission project and a competitively procured transmission project to address the regional need.[3570]

1672. Some commenters call for the Commission to expand the right-sizing reform to other categories of transmission facilities.[3571] Eversource argues that the Commission should encourage transmission providers to incorporate right-sizing considerations into other transmission planning processes, such as the reliability planning process, as appropriate.[3572] Similarly, ACORE and American Municipal Power request that the

[3568] Eversource Initial Comments at 53.

[3569] Entergy Initial Comments at 38.

[3570] Pennsylvania Commission Initial Comments at 21.

[3571] American Municipal Power Initial Comments at 27; Avangrid Initial Comments at 16; Clean Energy Associations Initial Comments at 26-27, 37; Eversource Initial Comments at 54; MISO Initial Comments at 88; NYISO Initial Comments at 59-60; PIOs Initial Comments at 57-58; TAPS Initial Comments at 6, 64-65.

[3572] Eversource Initial Comments at 54.

Commission clarify that right-sizing also applies in any short-term transmission planning for reliability and economic transmission projects.[3573] Grid United states that the Commission should require Long-Term Regional Transmission Planning to assess and allow for up-sizing transmission projects, such as building a single circuit transmission line that is double-circuit ready.[3574]

1673. Several commenters argue that the Commission should allow flexibility on the thresholds for evaluating transmission facilities for right-sizing.[3575] To prevent needless litigation that will cause delays and cost increases for customers, Dominion states that any final rule should be clear that transmission providers will not be penalized if a replacement project arises that was not previously identified.[3576]

1674. NYISO contends that the final rule should permit transmission providers, with input from state entities and stakeholders, to integrate planning for right-sizing

[3573] ACORE Initial Comments at 19; American Municipal Power Initial Comments at 27.

[3574] Grid United Initial Comments at 4.

[3575] American Municipal Power Initial Comments at 27; APPA Initial Comments at 48; Avangrid Initial Comments at 15-16; California Commission Initial Comments at 117; Clean Energy Associations Initial Comments at 36-37; Dominion Initial Comments at 72-73; EEI Initial Comments at 41; Eversource Initial Comments at 52-53; ISO-NE Initial Comments at 39; NARUC Initial Comments at 58-59, 63-64; National Grid Initial Comments at 40-41; NESCOE Initial Comments at 80; New York TOs Initial Comments at 18; NRECA Initial Comments at 67; NYISO Initial Comments at 9, 60; PG&E Reply Comments at 14-15; PPL Initial Comments at 37; US DOE Initial Comments at 48; Vermont State Entities Initial Comments at 13; WIRES Initial Comments at 10.

[3576] Dominion Initial Comments at 73.

transmission replacements into existing transmission planning processes, including by considering transmission facilities that they anticipate will be replaced in-kind when identifying transmission needs in short-term or long-term transmission planning.[3577]

1675. US DOE encourages the Commission to provide sufficient flexibility to ensure that the proposed reforms are cost-effective and do not overburden the transmission planning process. US DOE asserts that transmission providers should not be required to submit every in-kind replacement for all equipment above 230 kV for consideration for right-sizing and that regional transmission planning processes should not be required to consider each piece of equipment provided by each member of a transmission planning region.[3578]

1676. PG&E argues that the Commission should allow for flexibility in any right-sizing-related requirements, noting that a transmission provider may need to replace an aging or failing transmission facility sooner than a right-sized transmission project can be developed. In that case, PG&E states that the transmission owner would need to proceed with the replacement project to ensure reliability or protect public safety even if the RTO/ISO had determined that a transmission facility would benefit from being right-sized.[3579]

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[3577] NYISO Initial Comments at 9, 60.

[3578] US DOE Initial Comments at 48.

[3579] PG&E Reply Comments at 15.

### c. Commission Determination

1677. We adopt the NOPR proposal, with modification, to require that, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region evaluate whether transmission facilities (1) operating above a specified kV threshold and (2) that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address a Long-Term Transmission Need. To effectuate this reform, we also adopt the NOPR proposal, with modification, to require that, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider submit its in-kind replacement estimates (i.e., estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) for use in Long-Term Regional Transmission Planning. With respect to the specified kV threshold, transmission providers must propose on compliance a threshold that does not exceed 200 kV (e.g., 115 kV and above). In adopting the right-sizing reform in this final rule, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. We also adopt the NOPR proposals regarding a federal right of first refusal and cost allocation method for right-sized replacement transmission facilities, as discussed below.

1678. We adopt the NOPR proposal to define "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[3580] Additionally, we clarify that, for purposes of this right-sizing reform, an "in-kind replacement transmission facility" is a new transmission facility that: (1) would replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as needing to be replaced; (2) would result in no more than an incidental increase in capacity over the existing transmission facility identified as needing to be replaced;[3581] and (3) is located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility identified as needing to be replaced.

1679. Further, we clarify that a "right-sized replacement transmission facility" is a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also

[3580] NOPR, 179 FERC ¶ 61,028 at P 403 ("Right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies).").

[3581] The Commission has addressed the meaning of an incidental increase in the context of a replacement transmission facility in several orders. *See, e.g.*, *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at P 33, *order on reh'g*, 168 FERC ¶ 61,170 (2019); *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at P 68; *see also PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136 at P 84, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242 at P 54, *order on reh'g*, 176 FERC ¶ 61,053 (2021).

addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate. We believe these clarifications are necessary to ensure that use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.

1680. As an example, assume that transmission providers determine that an existing transmission facility included in a transmission provider's in-kind replacement estimate can be right-sized (Segment 1) and, together with a separate new transmission facility (Segment 2), is the more efficient or cost-effective solution to a Long-Term Transmission Need. In this example, Segment 1 is a new 50-mile, 345 kV transmission facility between interconnection points A and B that requires the expansion of an existing right-of-way, and replaces an existing 50-mile, 230 kV transmission facility between interconnection points A and B. Segment 2 in this example is a new 25-mile, 345 kV transmission facility requiring entirely new rights-of-way from interconnection points B to C. If both Segment 1 and Segment 2 are selected to address a Long-Term Transmission Need, then, for purposes of the requirements of this final rule, only Segment 1 would be considered a right-sized replacement transmission facility.

1681. Consistent with the NOPR proposal, and as discussed further below, the process under this proposed right-sizing reform entails taking the following steps, which

transmission providers must describe in their OATTs. The transmission providers in each transmission planning region must propose a point sufficiently early in each Long-Term Regional Transmission Planning cycle at which each individual transmission provider in the transmission planning region will submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if transmission providers identify a right-sized replacement transmission facility as a potential solution to a Long-Term Transmission Need as part of Long-Term Regional Transmission Planning, that right-sized replacement transmission facility must be evaluated in the same manner as any other proposed Long-Term Regional Transmission Facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. More specifically, it is at this stage of the right-sizing reform where transmission providers must use the in-kind replacement estimates to determine if in-kind replacement transmission facilities could be right-sized to more efficiently or cost-effectively address a Long-Term Transmission Need(s). If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution to a Long-Term Transmission Need, then the right-sized replacement transmission facility must be considered for selection.

1682. We find that a right-sized replacement transmission facility has the potential to both meet an individual transmission provider's responsibility to maintain the reliability of its existing transmission system and address a Long-Term Transmission Need more

efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility.[3582] Further, we find that, if opportunities for right-sized replacement transmission facilities are not considered, the Long-Term Regional Transmission Planning process may not select the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs, potentially rendering Commission-jurisdictional rates unjust and unreasonable.[3583]

1683. As noted above, for purposes of implementing the right-sizing requirements that we adopt in this final rule, transmission providers must propose on compliance a threshold that does not exceed 200 kV that is used in identifying the transmission facilities that an individual transmission provider anticipates replacing in-kind with a new transmission facility during the next 10 years, which it must then include in its in-kind replacement estimates. In other words, each transmission provider in the transmission planning region must include in its in-kind replacement estimates the transmission facilities operating at and above 200 kV, or at and above a lower proposed threshold, that it owns and anticipates replacing in-kind with a new transmission facility during the next 10 years.[3584] We find that this threshold strikes a reasonable balance between capturing

[3582] NOPR, 179 FERC ¶ 61,028 at P 406.

[3583] *Id*.

[3584] We note that while transmission providers may not propose a kV threshold that exceeds 200 kV, they may propose a lower kV threshold (e.g., 100 kV or 115 kV), which would require transmission providers in that transmission planning region to include in their in-kind replacement estimates a wider range of transmission facilities that they own and anticipate replacing in-kind with a new transmission facility during the next

the transmission facilities that are the most likely candidates for right-sizing without overburdening transmission providers by requiring them to identify all transmission facilities planned for in-kind replacement, including lower voltage transmission facilities that may be less likely to provide regional benefits, and therefore potentially less likely to be more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. Specifically, we believe adopting the 230 kV threshold proposed in the NOPR could have excluded from consideration some transmission facilities planned for in-kind replacement that are likely to provide regional benefits.[3585] In adopting a specified kV threshold (so long as that threshold does not exceed 200 kV), as opposed to the 230 kV threshold proposed in the NOPR, we note that the Commission "has wide discretion to determine where to draw administrative lines."[3586]

1684. We find that the requirement for transmission providers to identify a kV threshold not to exceed 200 kV to identify in-kind replacements recognizes that the NOPR proposal

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10 years.

[3585] For example, the maximum 200 kV threshold that we adopt here mirrors existing processes (e.g., CAISO) for determining whether a transmission facility provides regional benefits or more localized benefits. Appendix A of CAISO's OATT defines a "Large Project" as "[a] transmission upgrade or addition that exceeds $200 million in capital costs and consists of a proposed transmission line or substation facilities capable of operating at voltage levels greater than 200 kV." CAISO, CAISO eTariff, app. A, Definitions (0.0.0), § Large Project. Moreover, we note that a 200 kV threshold aligns with the 200 kV threshold for interconnection reforms discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Process section of this final rule.

[3586] *ExxonMobil Gas Mktg. Co. v. FERC*, 297 F.3d 1071, 1085 (D.C. Cir. 2002) (quoting *AT&T Corp. v. FCC*, 220 F.3d 607, 627 (D.C. Cir. 2000)).

did not align with the region-specific characteristics outlined by some transmission providers. For example, as ISO-NE notes, a large portion of ISO-NE's transmission system consists of 115 kV transmission facilities.[3587] We find that the maximum kV threshold that we adopt allows flexibility for transmission providers, like ISO-NE, to tailor their proposed kV threshold to their specific transmission planning regions (as long as the threshold they apply is equal or lower than 200 kV), while ensuring that the in-kind replacement transmission facilities that are most susceptible to modification that could more efficiently or cost-effectively address Long-Term Transmission Needs are considered for right-sizing.

1685. With regard to the 10-year timeframe for in-kind replacement estimates, we believe that 10 years is an appropriate timeframe to evaluate potential in-kind replacement transmission facilities for right-sizing because it balances the long lead times associated with developing certain transmission facilities with the uncertainty associated with the exact timing of when aging transmission facilities may need to be replaced.[3588] We also clarify that the 10-year timeframe for in-kind replacement estimates should reflect a transmission provider's estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years beginning at the start of each Long-Term Regional Transmission

[3587] ISO-NE Initial Comments at 39.

[3588] NOPR, 179 FERC ¶ 61,028 at P 406.

Planning cycle. Furthermore, we believe that a 10-year timeframe is more likely to capture a larger pool of potential in-kind replacement transmission facilities that would be eligible for right-sizing. We recognize, however, that transmission providers may obtain better information about a transmission facility's condition as the anticipated replacement date approaches and may also identify additional transmission facilities that require replacement in fewer than 10 years based on updated assessments of their condition. As such, we clarify that transmission providers may update the lists of transmission facilities that they anticipate replacing in subsequent transmission planning cycles if they believe that an anticipated in-kind replacement transmission facility is more urgently needed than previously thought or if existing transmission facilities do not deteriorate as quickly as previously expected.

1686. Several commenters oppose the right-sizing reform. They suggest that adopting the reform would harm competition or existing transmission planning processes that already evaluate whether replacement transmission facilities can be increased in transfer capability. We are unpersuaded by these arguments. We adopt the right-sizing reform because it captures certain transmission planning efficiencies by addressing aging transmission infrastructure issues while also providing an opportunity to increase transfer capability (i.e., develop the right-sized replacement transmission facility) to address Long-Term Transmission Needs more efficiently or cost-effectively. With respect to concerns about the right-sizing reform's impact on competition, we address that issue below under the section on Rights of First Refusal. Regarding commenters' arguments that existing transmission planning processes already evaluate whether replacement

transmission facilities can be right-sized, we note that we require transmission providers to consider right-sizing as part of Long-Term Regional Transmission Planning. If transmission providers wish to continue to consider right-sizing opportunities in some or all of their existing transmission planning processes in addition to Long-Term Regional Transmission Planning, this reform does not address those processes, and they may continue to adhere to existing practices that are not modified by this final rule. Further, we emphasize that transmission providers may propose compliance approaches that are consistent with or superior to these requirements, and as such, depending on their individual circumstances and approaches, may be able to demonstrate that a method akin to their existing practice is also appropriate for right-sizing in Long-Term Regional Transmission Planning.

1687. In response to PJM States' request for clarification regarding the interaction between existing processes and whether the right-sizing reform necessitates competitive transmission development processes, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. Regarding PJM States' request for clarification on competitive transmission development processes, we refer to the Right of First Refusal section below.

1688. In response to Exelon's concerns regarding the timing of replacement transmission facilities, we clarify that the 10-year timeframe associated with the right-sizing reform applies to transmission facilities that a transmission provider *anticipates* replacing. In other words, the requirement for a transmission provider to include in its in-kind

replacement estimates any transmission facilities that it anticipates replacing in-kind during the next 10 years does not create an obligation for the transmission provider to change any existing process that it has to identify which transmission facilities it anticipates replacing. However, a transmission provider must include in its in-kind replacement estimates any transmission facilities it anticipates replacing during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle, regardless of the process it uses to identify the facilities.

1689. In response to SERTP Sponsors and PG&E's arguments that replacement decisions may be triggered more by the conditions of a particular transmission facility than its age, we reiterate, consistent with the statement the Commission made in the NOPR, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining, and when necessary, replacing existing transmission facilities. We recognize that, as SERTP Sponsors note, replacement decisions may be triggered by other conditions than a transmission facility's age or condition, and since we recognize that a transmission provider may have existing rights and responsibilities under existing laws with respect to maintaining and, when necessary, replacing transmission facilities, we note that SERTP Sponsors, as well as any other transmission providers, may address such replacements of existing transmission facilities according to their existing processes.

1690. In response to Entergy's request for clarification regarding storm-hardening, we reiterate that the right-sizing reform we adopt here pertains to transmission facilities that a transmission provider anticipates replacing with an in-kind replacement transmission

facility. To the extent that storm-hardening transmission projects do not encompass the replacement of existing transmission facilities with an in-kind replacement transmission facility, those storm-hardening transmission projects need not be included on a transmission provider's list of in-kind replacement estimates.

1691. In response to US DOE's argument that transmission providers should not be required to submit every in-kind replacement for all equipment, we clarify that the right-sizing reform we adopt here requires transmission providers to list in their in-kind replacement estimates *only* the transmission facilities operating at and above the specified kV threshold that they own and anticipate replacing in-kind with a new transmission facility during the next 10 years, provided transmission providers may not propose a specified kV threshold higher than 200 kV.

1692. WIRES requests that the Commission clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities lower than 230 kV if existing transmission planning processes already do so. We clarify that, given our modification to the NOPR proposal, transmission providers may propose on compliance a threshold lower than 200 kV for considering right-sizing transmission facilities. We reiterate that the 200 kV threshold is a maximum threshold (i.e., transmission providers may not propose a right-sizing threshold higher than 200 kV).

### 2. Right of First Refusal

#### a. NOPR Proposal

1693. In the NOPR, the Commission proposed, for any right-sized replacement transmission facility that is selected to meet transmission needs identified through Long-

Term Regional Transmission Planning, to require the establishment of a federal right of first refusal for the transmission provider that includes the in-kind replacement transmission facility in its in-kind replacement estimates, which would extend to any portion of such a transmission facility located within the applicable transmission provider's retail distribution service territory or footprint.[3589]

**b. Comments**

1694. Some commenters support the proposed federal right of first refusal for right-sized replacement transmission facilities.[3590] AEP argues that without it, transmission providers may develop an in-kind replacement facility instead of the right-sized transmission facility identified in the regional transmission planning process.[3591] Similarly, PG&E states that providing a federal right of first refusal for right-sized replacement transmission facilities will provide an incentive for transmission providers to develop such projects, where appropriate.[3592]

[3589] *Id.* PP 408-409.

[3590] AEP Initial Comments at 46-47; Ameren Reply Comments at 14-15; Dominion Initial Comments at 75; EEI Initial Comments at 41; Exelon Initial Comments at 58; MISO TOs Initial Comments at 27-28; PG&E Reply Comments at 15-16; US Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

[3591] AEP Initial Comments at 46-47 (citing NOPR, 179 FERC ¶ 61,028 at PP 408-409).

[3592] PG&E Reply Comments at 16.

1695. MISO TOs argue that, whether through in-kind replacement or right-sized replacement, "what is being done is an upgrade of an existing transmission facility," for which the Commission has afforded transmission owners federal rights of first refusal through Order No. 1000 (and prior actions).[3593] US Chamber of Commerce states that a federal right of first refusal for right-sized replacement transmission facilities should also apply to right-sized transmission facilities, as it would eliminate incentives to withhold in-kind replacements from the regional transmission planning process.[3594]

1696. Ameren states that critics of the NOPR's proposal to provide transmission providers a federal right of first refusal for right-sizing projects question whether the Commission has met its FPA section 206 burden to demonstrate that the regional transmission planning tariffs are currently unjust and unreasonable or unduly discriminatory in order to justify this proposal.[3595] Ameren contends that this argument misses a critical point because, currently, replacement of transmission facilities in-kind is generally not subject to the regional transmission planning process or competitive transmission development processes. Ameren asserts that the Commission need not find any existing rate unjust and unreasonable in order to signal an intent to approve such

[3593] MISO TOs Initial Comments at 27-28.

[3594] US Chamber of Commerce Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at P 409).

[3595] Ameren Reply Comments at 14 (citing LS Power Initial Comments at 50).

right of first refusals for right-sizing projects when filed with the Commission under FPA section 205.[3596]

1697. Several commenters oppose the proposed federal right of first refusal for right-sized replacement transmission facilities.[3597] Massachusetts Attorney General argues that the Commission has not demonstrated a "rational connection" between the Commission's findings and the right-sizing reform. Massachusetts Attorney General adds that the NOPR proposal is directly at odds with the Commission's findings in Order Nos. 890 and 1000 and that the Commission fails to provide "good reasons" for departing from those prior findings.[3598] American Municipal Power argues that, even if incumbent transmission owners currently have a right of first refusal for local transmission facilities, that right should be limited to maintenance (i.e., in-kind replacements) and not situations

[3596] *Id*.

[3597] AEE Reply Comments at 31; American Municipal Power Initial Comments at 28-29; Anbaric Initial Comments at 7; California Commission Initial Comments at 115-117; California Water Initial Comments at 8-9; City of New York Initial Comments at 11-13; Competition Coalition Initial Comments at 64; Competition Coalition Reply Comments at 2; Industrial Customers Initial Comments at 4; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 22, 25-26, 84-85; Massachusetts Attorney General Initial Comments at 51-53; NextEra Initial Comments at 54-61; Northwest and Intermountain Initial Comments at 21-22; Pennsylvania Commission Initial Comments at 22-23; R Street Initial Comments at 3-4, 12-21; Resale Iowa Initial Comments at 8-9; TAPS Initial Comments at 68.

[3598] Massachusetts Attorney General Initial Comments at 40, 51 (citing 5 U.S.C. 706(2); 16 U.S.C. 825*l*(b); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n of the U. S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).

where a transmission facility would expand or enhance the transmission system.[3599] LS Power argues that the right-sizing proposal changes definitions in Order No. 1000, including the definitions of an upgrade and a local transmission facility, and allows a federal right of first refusal for transmission facilities located on an existing right-of-way instead of leaving the issue to state law.[3600] LS Power asserts that, even if the Commission could meet the first prong of its section 206 analysis and find that the existing transmission planning process is unjust and unreasonable, the Commission must still establish that the entirety of the replacement rate is just and reasonable which, LS Power argues, the Commission cannot because of the tie to a federal right of first refusal. Taken together, LS Power argues that the NOPR proposal, if adopted, would fail as a replacement rate.[3601] Furthermore, LS Power argues that the federal right of first refusal for right-sized replacement transmission facilities would essentially provide a federal franchise, mandating that transmission customers accept the ownership right of the existing transmission owners to continue in perpetuity.[3602]

1698. Northwest and Intermountain support clarifying that a federal right of first refusal for right-sized replacement transmission facilities does not apply to any facilities that

[3599] American Municipal Power Initial Comments at 28.

[3600] LS Power Initial Comments at 22.

[3601] *Id.* at 147-48 (citing *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 845 (D.C. Cir. 2006); *SEC v. Chenery Corp.*, 318 U.S. 80, 95 (1943)).

[3602] *Id.* at 84-85.

replace equipment that has reached the end of its useful life. Moreover, Northwest and Intermountain contend that the Commission should require a competitive solicitation for any right-sized transmission projects that meet regional transmission needs.[3603] AEE contends that the record does not support further action on the proposed federal right of first refusal for right-sized replacement transmission facilities, and instead reflects the complexity of the issues involved and the need for a holistic review of competitive transmission development processes and options for improving them.[3604]

1699. Several commenters raise concerns about the incentives that the proposed federal right of first refusal for right-sized replacement transmission facilities would introduce.[3605] Pennsylvania Commission argues that incumbent transmission owners may use it as a new tool to avoid competition by displacing other regional transmission facilities.[3606] Given that transmission providers may not secure cost recovery for imprudently incurred expenses, NextEra disagrees that, without a federal right of first

[3603] Northwest and Intermountain Initial Comments at 21-22.

[3604] AEE Reply Comments at 31.

[3605] Anbaric Initial Comments at 7; California Commission Initial Comments at 114-115; Competition Coalition Initial Comments at 65-67; LS Power Initial Comments at 81-82; Massachusetts Attorney General Initial Comments at 51-52; NextEra Initial Comments at 58; Pennsylvania Commission Initial Comments at 22; Resale Iowa Initial Comments at 8-9.

[3606] Pennsylvania Commission Initial Comments at 22.

refusal for right-sized replacement transmission facilities, incumbent transmission owners may engage in duplicative or inefficient transmission development.[3607]

1700. Some commenters oppose the proposed federal right of first refusal for right-sized replacement transmission facilities because they argue that it would increase costs for customers.[3608] California Water argues that allowing a federal right of first refusal for right-sized replacement transmission facilities would permit incumbent transmission owners to construct right-sized transmission facilities without any cost guardrails, which could end up being more expensive than the in-kind replacements.[3609] Alternatively, some commenters argue that their existing transmission planning processes already consider "right-sizing" replacement transmission facilities and may not include a federal right of first refusal.[3610]

1701. In response to claims that there is no logical basis for a federal right of first refusal for right-sized replacement transmission facilities, MISO TOs state that the proposal applies to upgrades of an existing transmission facility and that in Order No. 1000, the

[3607] NextEra Initial Comments at 59-61 (citations omitted).

[3608] *See* California Commission Initial Comments at 117; California Water Initial Comments at 9; Competition Coalition Initial Comments at 66-67; DC and MD Offices of People's Counsel Initial Comments at 47-48; R Street Reply Comments at 5-6; State Agencies Initial Comments at 21-22.

[3609] California Water Initial Comments at 9.

[3610] CAISO Initial Comments at 47-49; New York Commission and NYSERDA Initial Comments at 15-16; New York TOs Initial Comments at 17-18; NYISO Initial Comments at 58-59.

Commission expressly reserved a federal right of first refusal for an individual utility to upgrade its own property. As such, MISO TOs argue, a right-sizing requirement should neither deprive a transmission owner of its rights regarding its own property or its right to construct and own upgrades to its own system, nor should it implement an unconstitutional taking of such owner's property.[3611] Therefore, MISO TOs state that the final rule should clarify that nothing in the right-sizing proposal eliminates an incumbent transmission owner's federal right of first refusal for any transmission facilities selected through a right-sizing process.[3612]

### c. Commission Determination

1702. We adopt the NOPR proposal to require the establishment of a federal right of first refusal for a right-sized replacement transmission facility[3613] that is selected to meet

[3611] MISO TOs Reply Comments at 33 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 226, 319; Order No. 1000-A, 139 FERC ¶ 61,132 at P 426; *N.Y. Indep. Sys. Operator, Inc.*, 175 FERC ¶ 61,038, at PP 30, 33 (2021)).

[3612] MISO TOs Reply Comments at 33 (citing MISO TOs Initial Comments at 25-28).

[3613] As noted above, right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (e.g., advanced conductor technologies). Additionally, we reiterate that, as noted above, a right-sized replacement transmission facility is, for purposes of this right-sizing reform, a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for

Long-Term Transmission Needs. This federal right of first refusal will apply to the transmission provider that included in its in-kind replacement estimate the existing transmission facility that the right-sized replacement transmission facility would replace, and extends to any portion of the right-sized replacement facility located within that transmission provider's retail distribution service territory or footprint, recognizing that any such portion must satisfy the definition of a right-sized replacement facility, as revised by this final rule, including that the right-sized replacement transmission facility is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility.

1703. In adopting the NOPR proposal to require the establishment of a federal right of first refusal for a right-sized replacement transmission facility, we find that permitting a federal right of first refusal for right-sized replacement transmission facilities will encourage transmission providers to provide their best in-kind replacement estimates, because they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. As such, we find that a federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning, helping to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and likely built, and therefore that Commission-jurisdictional rates are just and reasonable. Moreover, we

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replacement in its in-kind replacement estimate.

note that the definitions of "in-kind replacement transmission facility" and "right-sized replacement transmission facility" that we adopt, as discussed above, are necessary to ensure that use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.[3614]

1704. We note that the establishment of a federal right of first refusal for right-sized replacement transmission facilities is an exception to Order No. 1000's general requirement for transmission providers to eliminate any federal right of first refusal for regional transmission facilities selected in a regional transmission plan.[3615] In response to comments challenging this approach as violating the precedent set in Order No. 1000, which eliminated federal rights of first refusal for new selected transmission facilities,[3616] we find that requiring a federal right of first refusal for right-sized replacement transmission facilities aligns with Order No. 1000.

1705. In Order No. 1000, the Commission required transmission providers to remove federal rights of first refusal from their OATTs because they undermined the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level, which could lead to unjust and unreasonable rates for Commission-jurisdictional services.[3617] The Commission found that federal rights of first refusal

[3614] *See supra* PP 1681-1683.

[3615] *See supra* P 1576.

[3616] Order No. 1000, 136 FERC ¶ 61,051 at P 313.

[3617] *Id.* PP 253, 256.

created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level.[3618] The Commission did not require the elimination of federal rights of first refusal for local transmission facilities,[3619] and did not alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to its own transmission facilities, regardless of whether the upgrade is selected.[3620]

1706. We find that the Commission's reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities. Specifically, requiring a federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level; rather, we find that it will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. When compared against the alternative of piecemeal development of in-kind replacement transmission facilities, a federal right of first refusal for right-sized transmission facilities does not frustrate the goals of Order No. 1000 or lead to inefficiency in transmission development because the right-sized replacement transmission facility represents the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs

[3618] *Id.* P 257.

[3619] *Id.* P 318.

[3620] *Id.* P 319 (citation omitted).

(otherwise it would not be selected). We recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing their transmission facilities. Because the right-sizing reform does not alter existing laws related to an individual transmission provider's ability to proceed with an in-kind replacement transmission facility, absent a federal right of first refusal, we believe the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely proceed to develop the less efficient or cost-effective in-kind replacement transmission facility. We find that the transmission provider would prefer the assurance of a federal right of first refusal for the in-kind replacement transmission facility over the uncertainty of subjecting a right-sized replacement transmission facility to the Order No. 1000 competitive transmission development process. Because of this incentive structure and the fact that the transmission provider holds the leverage as to whether to build a right-sized replacement transmission facility or a less efficient in-kind replacement transmission facility, the establishment of the federal right of first refusal is necessary to effectuate this reform and ensure that Commission-jurisdictional rates are just and reasonable.[3621]

1707. By establishing a process that requires transmission providers to evaluate opportunities to right-size in-kind replacement transmission facilities to meet Long-Term Transmission Needs, and by establishing a federal right of first refusal for such right-sized replacement transmission facilities, we believe that the right-sizing reform in this

[3621] *See* NOPR, 179 FERC ¶ 61,028 at P 408 & n.652.

final rule will encourage transmission providers to provide their best in-kind replacement estimates, as they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. Moreover, permitting a federal right of first refusal for right-sized replacement transmission facilities will enable transmission providers to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and that Commission-jurisdictional rates are consequently just and reasonable.[3622]

1708. In response to MISO TOs' request regarding upgrades to existing transmission facilities, we reiterate that nothing in the right-sizing reform affects the right of an incumbent transmission provider to build, own, and recover the costs for upgrades to its own transmission facilities, regardless of whether an upgrade to an existing transmission facility has been identified through a right-sizing process and selected to address Long-Term Transmission Needs.

1709. We deny Northwest and Intermountain's request to clarify that the right-sizing reform excludes transmission facilities that replace equipment that has reached the end of

[3622] In response to those commenters who argue that their existing transmission planning processes already consider "right-sizing" replacement transmission facilities without the inclusion of a federal right of first refusal, we note that, separate from compliance with this final rule, transmission providers in each transmission planning region can agree to participant funding arrangements for right-sized replacement transmission facilities that are not selected through Long-Term Regional Transmission Planning, in which case the requirement to establish a federal right of first refusal for right-sized replacement transmission facilities selected to meet Long-Term Transmission Needs would not apply.

its useful life. As explained above, the federal right of first refusal will apply to selected right-sized replacement transmission facilities, including those that are intended to replace transmission facilities that have reached the end of their useful life.

### 3. Cost Allocation

#### a. NOPR Proposal

1710. With respect to cost allocation, the Commission proposed that if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method. The Commission proposed that the costs the incumbent transmission provider would have otherwise incurred to construct the in-kind replacement transmission facility be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement. The Commission preliminarily found that it is just and reasonable and not unduly discriminatory or preferential for only the portion of the costs associated with a right-sized replacement transmission facility that is selected to be eligible to use the Long-Term Regional Transmission Cost Allocation Method because it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet the transmission needs identified in Long-Term Regional Transmission Planning.[3623]

1711. The Commission also proposed to require transmission providers in each transmission planning region to amend their regional transmission planning processes to

[3623] NOPR, 179 FERC ¶ 61,028 at P 410.

provide transparency with respect to which right-sized replacement transmission facilities have been selected (and thus found to be a more efficient or cost-effective transmission facility to meet regional transmission needs) and which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.[3624]

**b. Comments**

1712. Some commenters support the NOPR proposal that the incremental costs of right-sizing a transmission facility that is selected would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method.[3625] ACEG contends that without it, a large amount of new transmission investment—directed solely at replacement facilities—will be outside of Long-Term Regional Transmission Planning and thus not given an opportunity to contribute to the grid's overall efficiency and cost-effectiveness.[3626] Eversource asserts that, in New England, asset condition projects receive regional cost allocation, and requests clarification that the Commission is not proposing to disturb the existing cost allocation method for asset condition projects in ISO-NE that are not selected for right-sizing in Long-Term Regional Transmission

[3624] *Id.* P 413.

[3625] ACEG Initial Comments at 57-58; Eversource Initial Comments at 54; NARUC Initial Comments at 65; NESCOE Initial Comments at 81.

[3626] ACEG Initial Comments at 57-58.

Planning.[3627] NESCOE recommends that the Commission require transmission providers to explain on compliance the method that they will use to determine the incremental costs of right-sizing a replacement transmission facility. In addition, NESCOE supports the proposal to require transmission providers to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected.[3628]

1713. Other commenters support the proposed cost allocation for right-sized replacement transmission facilities, but express reservations.[3629] Entergy asserts that the Commission should clarify that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation.[3630] With regard to incremental costs, CTC Global urges the Commission to require the transmission planning process to be based on future needs, future benefits, total lifecycle costs, and total benefits for the life of the resource. More specifically, CTC Global suggests that when considering incremental costs, the Commission should consider including energy savings, generating capacity reduction

[3627] Eversource Initial Comments at 54.

[3628] NESCOE Initial Comments at 81.

[3629] CTC Global Initial Comments at 19; Dominion Initial Comments at 75-76; Entergy Initial Comments at 39; MISO Initial Comments at 87; NRG Initial Comments at 36-37.

[3630] Entergy Initial Comments at 39.

benefits, and resulting reductions in greenhouse gas emissions as benefits associated with the right-sized replacement transmission facility.[3631]

1714. Dominion states that it may be difficult to quantify and allocate the incremental costs of right-sizing a replacement transmission facility.[3632] MISO agrees, stating that it will be challenging to identify the portion of costs that should be recovered as part of the age and condition upgrade using one cost allocation method and a different cost allocation for the portion of the right-sized upgrade identified as part of Long-Term Regional Transmission Planning. MISO argues that this complexity will continue going forward given that the accounting for two types of cost allocation to different customers will have to be tracked for each right-sized replacement transmission facility.[3633]

1715. Some commenters oppose the NOPR proposal.[3634] LS Power argues that the proposal violates cost causation principles as it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of beneficiary analysis.[3635] Indicated PJM TOs state that the Commission should not impose any requirements with respect to the cost allocation of right-sized replacement

[3631] CTC Global Initial Comments at 19.

[3632] Dominion Initial Comments at 75-76.

[3633] MISO Initial Comments at 87.

[3634] Exelon Initial Comments at 59; Indicated PJM TOs Initial Comments at 47; LS Power Initial Comments at 86-87.

[3635] LS Power Initial Comments at 86-87 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, *reh'g denied*, 905 F.3d 671 (D.C. Cir. 2018)).

transmission facilities and instead should provide transmission providers with the flexibility to determine a cost allocation method.[3636] Exelon agrees, adding that the Commission's proposed approach creates unnecessary complications and adds a further variable (base versus incremental cost) to the already complex and often contentious cost allocation process. According to Exelon, the proposal (1) incorrectly assumes that a transmission owner has identified an in-kind replacement transmission facility and its cost; (2) incorrectly assumes that a perfect overlap exists between the displaced transmission facility (or need) and the right-sized replacement transmission facility; and (3) fails to address adjustments for cost savings or overruns on the right-sized portion of the transmission facility.[3637]

### c. Commission Determination

1716. We decline to adopt the NOPR proposal to require that, if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility will be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method, while the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission facility must be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement transmission facility. This is because we find persuasive comments that identify the complexities and challenges associated with

[3636] Indicated PJM TOs Initial Comments at 47 (citation omitted).

[3637] *See* Exelon Initial Comments at 59 & n.103.

tracking portions of costs of two different transmission projects through time, as well as allocating the costs of a right-sized replacement transmission facility pursuant to two separate cost allocation methods.[3638] While the approach that the NOPR proposed to require may still be a just and reasonable cost allocation approach for right-sized replacement transmission facilities, should the relevant transmission providers *choose* to take on these challenges and address them adequately, we find it appropriate to provide flexibility to transmission providers to propose a cost allocation method for selected right-sized replacement transmission facilities. However, in providing such flexibility, transmission providers must nevertheless demonstrate on compliance that the cost allocation method for selected right-sized replacement transmission facilities is just and reasonable and not unduly discriminatory or preferential and, consistent with cost causation, allocates costs in a manner that is at least roughly commensurate with the estimated benefits of such facilities.[3639]

1717. Further, we also require transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected,

[3638] Dominion Initial Comments at 75-76; Exelon Initial Comments at 59; MISO Initial Comments at 87.

[3639] *See ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

as well as which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.

1718. We disagree with LS Power's assertion that the right-sizing cost allocation method proposed in the NOPR violates cost causation principles because it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of other potential beneficiaries.[3640] The customers of the transmission provider that would be allocated the costs associated with the original in-kind replacement transmission facility would have otherwise been responsible for paying those costs had the in-kind replacement transmission facility not been right-sized. Further, we find that it is not unjust, unreasonable, or unduly discriminatory or preferential that, for a right-sized replacement transmission facility selected, only the portion of the costs associated with right-sizing be eligible to use the Long-Term Regional Transmission Cost Allocation Method. Specifically, we find that it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning. As such, we disagree that allowing only the incremental costs of right-sizing the right-sized replacement transmission facility to be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method would violate cost causation principles.

[3640] LS Power Initial Comments at 86-87 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254).

1719. As we note above, we find merit with respect to commenters' concerns about the difficulty in determining the portion of the costs of a right-sized replacement transmission facility attributable to right-sizing and the complexity in tracking portions of differing cost allocation methods through time. For this reason, to the extent that transmission providers propose to allocate the costs of right-sized replacement transmission facilities pursuant to the cost allocation method described in the NOPR, we require the transmission providers to explain on compliance (1) the method that they will use to determine the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, and (2) the method by which they will track the portion of costs over time that are allocated in accordance with the Long-Term Regional Transmission Cost Allocation Method (or, if adopted, subject to a State Agreement Process), as well as the portion of costs that would have been allocated pursuant to the cost allocation method that otherwise would have applied to the in-kind replacement transmission facility. We believe that transmission providers are best positioned to determine both the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, as well as how to best track these costs over time for purposes of cost allocation.

1720. In response to Eversource and Entergy's requests that the Commission clarify the cost allocation method for in-kind replacement transmission facilities that are not selected

for right-sizing,[3641] we clarify that we are not requiring any changes pursuant to this right-sizing requirement that would affect the existing cost allocation method(s) for in-kind replacement transmission facilities that are not identified for right-sizing, or for the costs of the underlying in-kind replacement transmission facilities that would have been incurred absent right-sizing. Similarly, in response to Entergy's request for clarification that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation, we clarify that the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission facility must be allocated in a manner consistent with the cost allocation method that would have otherwise applied to that facility, which could include a regional cost allocation method.

1721. We also confirm, in response to comments from CTC Global, that benefits associated with a potential right-sized replacement transmission facility to address Long-Term Transmission Needs should be evaluated in the same manner as for any potential regional transmission facility that could address those needs, which includes evaluating all of the costs of, and all of the benefits provided by, the right-sized replacement transmission facility consistent with reforms outlined in this final rule.

1722. In response to Exelon's comments that the NOPR proposal relies on incorrect assumptions regarding the transmission provider identifying an in-kind replacement transmission facility and its cost, as well as there being an overlap between the displaced

[3641] Entergy Initial Comments at 39; Eversource Initial Comments at 54.

transmission facility and the right-sized replacement transmission facility, we disagree and note that these conditions are prerequisites that serve as the foundation for the right-sizing requirement. Where a transmission provider has not identified an in-kind replacement transmission facility that could be right-sized to address Long-Term Transmission Needs more efficiently or cost-effectively, no basis exists to select a right-sized replacement transmission facility.

#### 4. Miscellaneous

##### a. Comments

1723. Some commenters recommend that the Commission adopt confidentiality safeguards.[3642] AEP and Indicated PJM TOs contend that the Commission must adopt confidentiality provisions to ensure that information related to right-sizing is not shared beyond the regional planning entity because identification of end-of-life transmission facilities demonstrates potential vulnerabilities that could create security and reliability risks and could also provide advantages to competitors.[3643] WIRES argues that the Commission should allow for the transmission owner to provide to the transmission provider a non-public, confidential, non-binding list of transmission facilities that may need to be replaced based on an appropriate time horizon as determined by the

[3642] AEP Initial Comments at 46; Exelon Initial Comments at 57-58; Indicated PJM TOs Initial Comments at 45-46; SERTP Sponsors Initial Comments at 39; WIRES Initial Comments at 10.

[3643] AEP Initial Comments at 46; Indicated PJM TOs Initial Comments at 45.

transmission provider.[3644] SERTP Sponsors request that the Commission protect CEII information for transmission facilities that are anticipated to be replaced.[3645]

1724. Conversely, PJM States request that the Commission require the information on the in-kind replacement estimate list to be non-confidential to the greatest extent possible or to require justification as to why confidentiality is merited.[3646]

1725. Several commenters call for the Commission to increase scrutiny on, or alter the presumption of prudence for, transmission projects related to the right-sizing reform.[3647] American Municipal Power argues that if an incumbent transmission owner replaces local transmission facilities at the end of their useful lives despite a determination that a right-sized replacement transmission facility is the more efficient or cost-effective transmission solution, the incumbent transmission owner's in-kind replacement should be presumed to be unjust and unreasonable for purposes of cost recovery.[3648]

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[3644] WIRES Initial Comments at 10.

[3645] SERTP Sponsors Initial Comments at 39.

[3646] PJM States Initial Comments at 7-8.

[3647] American Municipal Power Initial Comments at 29-30; California Commission Initial Comments at 114-115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 5; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 23-24; Pine Gate Initial Comments at 49-50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6-7, 67-68.

[3648] American Municipal Power Initial Comments at 29.

1726. ACEG asserts that the Commission has the authority under FPA section 205 to review replacement transmission facility projects and address problems in the local transmission planning process.[3649] LS Power argues that the Commission should use its existing authority to confirm through show cause orders that transmission providers are evaluating whether local transmission solutions can be displaced by a regional transmission solution that is more efficient or cost-effective.[3650]

1727. Similarly, TAPS asserts that the NOPR imposes no consequences on transmission owners that proceed with in-kind replacement projects even when the transmission planning region has selected more efficient and cost-effective alternatives for regional cost allocation. TAPS argues that the Commission should exclude cost recovery for such facilities from the scope of formula rates and require transmission owners to make a separate filing pursuant to FPA section 205. Alternatively, TAPS states that the Commission should impose a presumption of imprudence and require such transmission owners to demonstrate that the proposed replacement is more cost-effective and efficient than the alternative selected by the transmission planning region.[3651]

1728. On the other hand, PG&E argues that the Commission should clarify that a transmission owner's right to decline to proceed with a selected right-sized replacement

[3649] ACEG Initial Comments at 57.

[3650] LS Power Initial Comments at 145 (citing LS Power ANOPR Initial Comments at 134-135).

[3651] TAPS Initial Comments at 6-7, 67-68 (citations omitted).

transmission facility does not justify disallowance of cost recovery for the in-kind replacement transmission facility.[3652]

1729. Several commenters support consideration of alternative transmission technologies and grid enhancing technologies when evaluating right-sized replacement transmission facilities.[3653] CTC Global urges the Commission to require all transmission owners with a line requiring in-kind replacement within 10 years to analyze whether a transmission line's conductor should be replaced with an advanced conductor through rebuild or reconductoring.[3654] PIOs argue that right-sizing opportunities should include increasing voltage, adding circuits, and utilizing advanced technologies, and further argue that right-sized replacement transmission facilities that use grid enhancing technologies can create economies of scale to capture public policy and economic benefits in addition to reliability.[3655] VEIR agrees with the Commission's proposal to include advanced conductors in its definition of right-sizing, explaining that superconductors can enable a five-fold increase in the power flow capacity of an existing transmission corridor. VEIR

[3652] PG&E Initial Comments at 14.

[3653] CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5-6; NARUC Initial Comments at 58-59; PIOs Initial Comments at 57-58; VEIR Initial Comments at 6.

[3654] CTC Global Initial Comments at 18.

[3655] PIOs Initial Comments at 57-58 (citing PIOs ANOPR Initial Comments at 50).

therefore urges the Commission to explicitly affirm that the deployment of advanced conductors would constitute right-sizing.[3656]

1730. Some commenters argue that the NOPR's right-sizing proposal is insufficient and call upon the Commission to take further action.[3657] For example, ACEG, American Municipal Power, and California Commission argue that the Commission should expand the scope of the right-sizing proposal.[3658] American Municipal Power argues that the Commission should require RTOs/ISOs to plan for all new transmission facilities that have regional impacts, including: (1) transmission facilities that meet the North American Electric Reliability Corporation Bulk Electric System definition; and (2) transmission projects that will replace an existing transmission facility that was turned over to the RTO/ISO irrespective of the voltage.[3659] Similarly, LS Power argues that the Commission has the authority to require regional transmission planning for existing

[3656] VEIR Initial Comments at 6.

[3657] ACEG Initial Comments at 57; American Municipal Power Initial Comments at 25-26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106-108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68-70; Grid United Initial Comments at 3-4; Harvard ELI Initial Comments at 4-5; LS Power Initial Comments at 136, 138, 141-142, 145-146; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64-65.

[3658] *See* ACEG Initial Comments at 57-58; American Municipal Power Initial Comments at 25-26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 113-118.

[3659] American Municipal Power Reply Comments at 5.

transmission facilities reaching the end of operational life, and that such transmission planning should be performed by an independent transmission planner.[3660]

1731. Massachusetts Attorney General asserts that all right-sized replacement transmission facilities should be subject to cost containment, stating that transmission owners may present transmission projects that look like good opportunities for right-sizing at low cost, but without cost containment and competition, the final cost could be much higher.[3661] ACEG argues that the Commission could issue policy guidance regarding its scope and process for review of new replacement transmission facilities in transmission rate cases.[3662]

1732. Competition Coalition and LS Power argue that the Commission should protect customers by expanding the benefits of regional transmission planning and competition to all transmission projects 100 kV and above.[3663] Ameren responds that this request by LS Power to expand the range of transmission projects subject to competition is outside the scope of the NOPR.[3664]

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[3660] LS Power Initial Comments at 83-84, 141 (citations omitted).

[3661] Massachusetts Attorney General Initial Comments at 52.

[3662] ACEG Initial Comments at 57 (citation omitted).

[3663] Competition Coalition Initial Comments at 68-69; LS Power Initial Comments at 136, 141 (citations omitted); LS Power and NRG Post-Technical Conference Comments at 10 & n.17 (noting that its comment on this issue is attributed to LS Power only).

[3664] Ameren Reply Comments at 15 (citing LS Power Initial Comments at 116).

1733. Harvard ELI favors additional scrutiny of right-sized replacement transmission facilities. Harvard ELI states generally that the Commission could address the perverse incentives of current rules leading to a focus on local transmission development by subjecting local transmission planning to heightened scrutiny.[3665]

1734. PIOs claim that the Commission should consider an "ROE subtractor" analogous to an ROE adder that automatically reduces ROE with certain criteria.[3666]

### b. Commission Determination

1735. We decline to adopt ACEG's and LS Power's requests that the Commission *itself* review in-kind replacement transmission facilities, via section 205 or 206 authority or through policy guidance, to ensure that they cannot be displaced by a regional transmission solution that is more efficient or cost-effective.[3667] These arguments are outside the scope of this proceeding because the Commission did not propose in the NOPR that the Commission review in-kind replacement transmission facilities or local transmission facilities.

1736. We decline to adopt commenters' requests for additional confidentiality safeguards related to right-sizing.[3668] We note that a transmission provider's list of in-

[3665] Harvard ELI Initial Comments at 4.

[3666] PIOs Initial Comments at 53.

[3667] ACEG Initial Comments at 57 (citations omitted); LS Power Initial Comments at 145-146 (citing LS Power ANOPR Initial Comments at 134-135).

[3668] AEP Initial Comments at 46; Exelon Initial Comments at 57-58; Indicated PJM TOs Initial Comments at 45-46; SERTP Sponsors Initial Comments at 39; WIRES

kind replacement estimates (i.e., estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) is a non-binding estimate and does not require that transmission provider to undertake replacement work. To the extent that customers or stakeholders request access to a transmission provider's list of in-kind replacement estimates, that transmission provider may subject access to that list of in-kind replacement estimates to confidentiality provisions. However, once the transmission providers have determined, as part of Long-Term Regional Transmission Planning, that an in-kind replacement transmission facility can be right-sized to constitute a right-sized replacement transmission facility, we find that the transmission providers must make public the underlying in-kind replacement transmission facility.

1737. We decline to adopt commenter requests for increased scrutiny of, or altering the presumption of prudence for, transmission projects related to right-sizing.[3669] We reject these requests as outside the scope of this proceeding because the Commission did not propose in the NOPR to increase scrutiny of in-kind replacement transmission facilities

Initial Comments at 10.

[3669] American Municipal Power Initial Comments at 29-30; California Commission Initial Comments at 114-115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 4; Massachusetts Attorney General Initial Comments at 52; Mississippi Commission Initial Comments at 30; Ohio Consumers Initial Comments at 23; Pine Gate Initial Comments at 49-50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6-7, 67.

beyond the right-sizing proposal and did not propose to alter existing Commission policy on prudence. Likewise, in response to PG&E's request for clarification that a transmission provider's declining to proceed with a right-sized replacement transmission facility does not justify disallowance of cost recovery for the in-kind replacement transmission facility, nothing in the reforms we adopt here alters existing Commission policy on cost recovery for transmission facilities.[3670]

1738. We acknowledge commenter support for the consideration of alternative transmission technologies with regard to right-sizing.[3671] However, we find that adopting additional requirements for consideration of alternative transmission technologies with respect to right-sizing are unnecessary. This is because, as discussed in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final rule, we require transmission providers in each transmission planning region to more fully consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning, dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching.[3672] We believe that the

[3670] *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985) (explaining that the Commission evaluates "prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses").

[3671] CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5-6; NARUC Initial Comments at 58-59, 63-64; PIOs Initial Comments at 57-58; VEIR Initial Comments at 6.

[3672] *See* Consideration of Dynamic Line Ratings and Advanced Power Flow

requirements in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final rule adequately address consideration of alternative transmission technologies in the regional transmission planning process, including when considering right-sizing.

1739. Some commenters request that the Commission take other actions and suggest alternative reforms to the Commission's proposal related to right-sizing.[3673] We find these requests to be outside the scope of this proceeding and lacking in record support to adequately consider whether to adopt them in this final rule.

## X. Interregional Transmission Coordination

### A. NOPR Proposal

1740. In the NOPR, the Commission proposed to require each transmission provider to revise its existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.[3674]

1741. Specifically, the Commission proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional

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Control Devices section.

[3673] ACEG Initial Comments at 57; American Municipal Power Initial Comments at 5, 25; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106-108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68-69; Grid United Initial Comments at 3-4; Harvard ELI Initial Comments at 4; LS Power Initial Comments at 83, 136, 138, 141-142, 145-146; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64-65.

[3674] NOPR, 179 FERC ¶ 61,028 at P 426.

transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.[3675]

1742. The Commission also proposed to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.[3676] The Commission noted that this proposal would align the existing requirement for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located with the proposed requirement for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

[3675] *Id.* P 427.

[3676] *Id.* P 428.

1743. The Commission stated that this proposed reform aims to ensure that transmission needs driven by changes in the resource mix and demand identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes.[3677] The Commission preliminarily concluded that the proposed interregional transmission coordination reforms will also ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively meet the transmission needs identified through Long-Term Regional Transmission Planning, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

### B. Comments

1744. Many commenters support the Commission's proposal to require transmission providers to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.[3678] Such commenters assert that this proposed reform would give transmission

[3677] *Id.* P 429.

[3678] Acadia Center and CLF Initial Comments at 23-24; ACEG Initial Comments at 74; Ameren Initial Comments at 47; Arizona Commission Initial Comments at 10; BP Initial Comments at 13-14; Breakthrough Energy Initial Comments at 2; California Commission Initial Comments at 118-121; California Energy Commission Initial Comments at 4; California Water Initial Comments at 20-21; Clean Energy Associations Initial Comments at 40-42; EEI Initial Comments at 48; Enel Initial Comments at 4-5; Eversource Initial Comments at 55-56; Exelon Initial Comments at 60-61; Grid United Initial Comments at 7-9; Idaho Power Initial Comments at 13; Indiana Commission Initial Comments at 7-9; Interwest Initial Comments at 18-20; MISO Initial Comments at 88-89; NARUC Initial Comments at 67-70; National and State Conservation

providers in neighboring transmission planning regions the opportunity to consider whether interregional transmission facilities could meet the transmission needs identified through Long-Term Regional Transmission Planning in a more efficient or cost-effective manner than separate regional transmission facilities, which would help to ensure just and reasonable rates.

1745. Some commenters condition their support on the Commission providing transmission providers with flexibility. For example, EEI asserts that providing transmission providers with flexibility in developing Long-Term Regional Transmission Planning will help ensure that transmission planning regions can determine the processes that work for them and collaborate with neighboring regions.[3679] Idaho Power requests that the Commission allow flexibility in the methods used to determine transmission benefits.[3680] Pennsylvania Commission conditions its support on the Commission maintaining flexibility for transmission providers to define criteria for considering and

Organizations Initial Comments at 1-2; Northwest and Intermountain Initial Comments at 10, 22; OMS Initial Comments at 18-20; Pennsylvania Commission Initial Comments at 23-25; Pine Gate Initial Comments at 50-51; PIOs Initial Comments at 75-79; PJM Initial Comments at 9-10, 123-125; R Street Initial Comments at 4-5; State Agencies Initial Comments at 22-23; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments at 3); US Climate Alliance Initial Comments at 3; US DOE Initial Comments at 38-40; US DOJ and FTC Initial Comments at 19-20.

[3679] EEI Initial Comments at 48.

[3680] Idaho Power Initial Comments at 13.

selecting transmission facilities, including criteria that permit the selection of proposed regional transmission facilities over a proposed interregional transmission facility.[3681]

1746. Other commenters suggest that the Commission could improve the proposed reforms to interregional transmission coordination by requiring additional information sharing. For example, US DOE recommends that the Commission require neighboring transmission planning regions to share information with one another about their geographic zones.[3682] California Energy Commission recommends that transmission providers be required to share with neighboring transmission planning regions how other planning processes, such as integrated resource plans, resource adequacy, and state requirements, are considered in regional transmission planning.[3683] State Agencies suggest that transmission providers should provide an annual report to the Commission on their interregional transmission coordination activities, including the number of interregional transmission projects identified, the results of the cost/benefit evaluation overall and to each transmission planning region, whether other regions have been or should be included to maximize the value of the project, and any barriers to development of interregional transmission projects.[3684] NARUC urges the Commission to encourage

[3681] Pennsylvania Commission Initial Comments at 24-25.

[3682] US DOE Initial Comments at 18-20.

[3683] California Energy Commission Initial Comments at 4.

[3684] State Agencies Initial Comments at 23.

additional coordination and information sharing between non-RTO/ISO transmission planning regions like NorthernGrid and WestConnect.[3685]

1747. Pattern Energy asserts that the Commission should require neighboring transmission planning regions to hold forums for stakeholders to discuss right-sizing or expanding proposed regional transmission facilities in consideration of the needs of both regions.[3686] Further, Pattern Energy argues that if no interregional transmission facilities are approved in a Long-Term Regional Transmission Planning cycle, the Commission should require transmission planning regions to provide transparent reasoning to help stakeholders and regulators understand whether interregional transmission coordination requires reform.[3687]

1748. MISO asserts that the Commission should institute a separate and longer compliance period for the interregional transmission coordination requirements than for the regional transmission planning requirements proposed in this rulemaking.[3688] Further, to reduce the compliance burden on transmission providers, MISO requests that the Commission include all interregional transmission coordination and planning

[3685] NARUC Initial Comments at 69-70.

[3686] Pattern Energy Reply Comments at 14.

[3687] *Id.* at 14-15.

[3688] MISO Initial Comments at 89.

requirements in a single rulemaking rather than require interregional compliance in multiple, separate proceedings.[3689]

1749. Many commenters assert that the Commission's proposals with respect to interregional transmission coordination do not go far enough.[3690] Several commenters urge the Commission to require holistic interregional transmission planning and cost allocation.[3691] Some commenters encourage the Commission to require a minimum amount of Interregional Transfer Capability between neighboring transmission planning regions.[3692] Several commenters urge the Commission to require neighboring

[3689] *Id.* at 88-89.

[3690] *See, e.g.*, ACEG Initial Comments at 76-78; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 41-42; Enel Initial Comments at 4-5; Evergreen Action Initial Comments at 5-6; Eversource Initial Comments at 56; Grid United Initial Comments at 7-8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18-19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12-15; Pine Gate Initial Comments at 50-51; PIOs Initial Comments at 75-77; PJM Initial Comments at 9-10, 123-124; Rail Electrification Initial Comments at 2, 8-11; RMI Initial Comments at 1-2; State Agencies Initial Comments at 23; Transmission Dependent Utilities Initial Comments at 6-7; US DOE Initial Comments at 38-39; Xcel Initial Comments at 17.

[3691] *See, e.g.*, ACEG Initial Comments at 76-78; Clean Energy Associations Initial Comments at 41-42; Enel Initial Comments at 4-5; Evergreen Action Initial Comments at 5-6; Grid United Initial Comments at 7-8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18-19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12-15; Pine Gate Initial Comments at 50-51; PIOs Initial Comments at 75-77; PJM Initial Comments at 9-10, 123-124; Rail Electrification Initial Comments at 2, 8-11; RMI Initial Comments at 1-2; Shell Reply Comments at 8-9; US DOE Initial Comments at 38-39; Xcel Initial Comments at 17.

[3692] *See, e.g.*, ACEG Initial Comments at 70-76; AEP Initial Comments at 17-18; Breakthrough Energy Initial Comments at 2; Evergreen Action Initial Comments at 5-6;

transmission planning regions to adopt a common system model and planning assumptions, common Long-Term Scenarios, and consistent data inputs.[3693] AEP argues that the Commission should require consistency across transmission planning regions in terms of the transmission planning horizon, planning frequency, and minimum set of benefits considered.[3694]

1750. MISO encourages the Commission to examine interregional transmission planning, including analysis of the assumptions related to transfer capacity and the effectiveness of collaboration between RTO and non-RTO neighbors, in a separate docket.[3695] Eversource and State Agencies suggest that the Commission encourage RTOs/ISOs to increase staffing to address interregional transmission planning.[3696] National Grid suggests that the Commission provide appropriate rate incentives for interregional transmission facilities.[3697] Rail Electrification urges the Commission to

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Eversource Initial Comments at 55-56; Interwest Initial Comments at 18-20; Invenergy Initial Comments at 20-27; Invenergy Reply Comments at 19-22; Kansas Commission Initial Comments at 4-10; PJM Initial Comments at 9-10, 123-125.

[3693] Hannon Armstrong Reply Comments at 1; Invenergy Reply Comments at 19-22; National Grid Initial Comments at 19-20; Transmission Dependent Utilities Initial Comments at 6-7; US DOE Initial Comments at 18-21.

[3694] AEP Reply Comments at 3-5.

[3695] MISO Reply Comments at 29-30.

[3696] Eversource Initial Comments at 55-56; State Agencies Initial Comments at 23.

[3697] National Grid Initial Comments at 20.

support the siting of large interregional transmission facilities along available interstate transportation rights-of-way to advance the grid of the future more quickly.[3698]

### C. Commission Determination

1751. We adopt, with modification, the NOPR proposal to require transmission providers in each transmission planning region to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in this final rule. Specifically, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes, as needed) to provide for: (1) the sharing of information regarding their respective Long-Term Transmission Needs, as well as Long-Term Regional Transmission Facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs.

1752. Additionally, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes, as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to Long-Term Transmission Needs. We find that this requirement will align the existing requirement, for an entity to propose

[3698] Rail Electrification Initial Comments at 8-12.

an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located, with the new requirement in this final rule for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

1753. In response to commenter requests for additional information sharing and transparency of the interregional transmission coordination process, we find that additional transparency as applied to Long-Term Regional Transmission Planning is warranted.[3699] Order No. 1000 requires that transmission providers in neighboring transmission planning regions maintain a website or e-mail list for the communication of information related to interregional transmission coordination procedures.[3700] We modify the NOPR proposal, and require transmission providers in each transmission planning region to provide the following additional information concerning Long-Term Regional Transmission Planning on their public website or through the email list used for communication of information related to interregional transmission coordination procedures: (1) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings; (2) any interregional transmission facilities proposed or identified in response to Long-Term Transmission Needs; (3) the voltage level,

[3699] *See, e.g.*, California Energy Commission Initial Comments at 4; NARUC Initial Comments at 69-70; Pattern Energy Reply Comments at 14-15; State Agencies Initial Comments at 23.

[3700] Order No. 1000, 136 FERC ¶ 61,051 at PP 345, 458.

estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning; (4) the results of any cost-benefit evaluation of such interregional transmission facilities, with such results including both any overall benefits identified (which may occur across multiple transmission planning regions), as well as any benefits particular to each transmission planning region; and (5) the interregional transmission facilities, if any, selected to meet Long-Term Transmission Needs. We find that this modification will enhance transparency and facilitate stakeholder engagement in the interregional transmission coordination procedures as applied to Long-Term Regional Transmission Planning, thereby ensuring just and reasonable rates. We believe that this requirement to make this information publicly available will not create a significant burden because transmission providers will already share or develop such information with the transmission providers in neighboring transmission planning regions to comply with the requirement in this final rule to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms.

1754. Taken together, we find that these reforms will ensure that Long-Term Transmission Needs identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes. Further, doing so will ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively address

the identified Long-Term Transmission Needs, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

1755. We decline to require the transmission providers in neighboring transmission planning regions to hold forums for stakeholders to discuss right-sizing or expanding proposed regional transmission facilities in consideration of the transmission needs of both regions, as requested by Pattern Energy. The Commission did not propose such a reform in the NOPR, and we decline to require it here.

1756. Regarding Idaho Power's request that the Commission provide transmission providers with flexibility in the methods used to determine the benefits of interregional transmission facilities, we note that this issue is addressed above in the Evaluation of the Benefits of Regional Transmission Facilities section of this final rule.[3701] Regarding Pennsylvania Commission's comment that its support for the interregional transmission coordination reforms proposed in the NOPR are conditioned on the Commission maintaining flexibility for transmission providers to define criteria for considering and selecting transmission facilities, we note that the requirements regarding selection criteria are addressed in the section above on the Evaluation and Selection of Long-Term Regional Transmission Facilities.[3702]

[3701] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

[3702] *See supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

1757. Regarding MISO's request for a longer compliance period for transmission providers to comply with the interregional transmission coordination requirements of this final rule, we address MISO's request in the Compliance section below.[3703]

1758. With respect to commenter requests for the Commission to: (1) require holistic interregional transmission planning and cost allocation; (2) require a minimum amount of Interregional Transfer Capability between neighboring transmission planning regions; (3) require neighboring transmission planning regions to adopt a common system model, consistent data inputs, and a uniform transmission planning horizon and transmission planning frequency; (4) encourage RTOs/ISOs to increase staffing to address interregional transmission planning; (5) adopt new rate incentives for interregional transmission facilities; and (6) support the siting of large interregional transmission facilities along available transportation rights-of-way, we find such requests to be outside the scope of this proceeding. We recognize that one or more of these reforms hold the potential to enhance system reliability or provide significant consumer benefits. However, the Commission did not propose such reforms in the NOPR, and we decline to adopt them in the final rule. However, we note that the Commission currently has an open proceeding in Docket No. AD23-3-000 to consider whether and how to establish a minimum requirement for Interregional Transfer Capability, and may consider further reforms in other proceedings, as appropriate.[3704]

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[3703] *See infra* Compliance Procedures section.

[3704] *See* Supplemental Notice of Staff-Led Workshop, *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Docket

## XI. Compliance Procedures

### A. NOPR Proposal

1759. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within eight months of the effective date of any final rule in this proceeding revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in any final rule in this proceeding.[3705] The Commission proposed that transmission providers that are not public utilities would have to adopt the requirements adopted in any final rule in this proceeding as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[3706]

1760. Additionally, in the NOPR, the Commission proposed to require transmission providers to demonstrate on compliance that proposed variations from the requirements in the final rule are consistent with or superior to the final rule.[3707]

### B. Comments

1761. Several commenters support a compliance period of eight months or more to allow stakeholders, including Relevant State Entities, sufficient time to negotiate and agree on proposals to comply with this rulemaking.[3708] PJM states that while an eight-month

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No. AD23-3-000 (Nov. 30, 2022).

[3705] NOPR, 179 FERC ¶ 61,028 at P 430.

[3706] *Id.* P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63).

[3707] *Id*. PP 74-75, 105, 229.

[3708] Idaho Power Initial Comments at 14; ISO-NE Initial Comments at 41; MISO

period to submit compliance filings is reasonable, the Commission should thereafter allow time for transmission planners to develop the tools and hire the employees they will need to implement the final rule.[3709] NEPOOL states that the Commission should be flexible in considering requests for extensions of time.[3710] Pacific Northwest State Agencies urge the Commission to provide flexibility rather than a rigid time period of eight months to comply with the final rule.[3711]

1762. Certain TDUs argue that the Commission should require transmission providers to submit compliance filings no later than 270 days after the final rule becomes effective to reflect the requirements to include an *ex ante* Long-Term Regional Transmission Cost Allocation Method, define benefits, and identify the method by which benefits are selected.[3712]

1763. Some commenters request that the Commission provide longer than eight months to comply with the final rule. For example, NARUC argues that eight months is unlikely

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Initial Comments at 90; NARUC Initial Comments at 50-51; NEPOOL Initial Comments at 10; NESCOE Reply Comments at 9 (citing ISO-NE Initial Comments at 41); North Carolina Commission and Staff Initial Comments at 17; Northwest and Intermountain Initial Comments at 22-23; Pacific Northwest State Agencies Initial Comments at 28; PJM Initial Comments at 10, 129.

[3709] PJM Initial Comments at 10, 129.

[3710] NEPOOL Initial Comments at 10.

[3711] Pacific Northwest State Agencies Initial Comments at 28.

[3712] Certain TDUs Initial Comments at 16.

to allow sufficient time for Relevant State Entities to meaningfully engage.[3713] Given the complexity of the proposals and the need to coordinate with stakeholders, Idaho Power and ISO-NE propose that the Commission allow at least one year for transmission providers to comply with the final rule.[3714] For similar reasons, MISO urges the Commission to provide a compliance period of at least 18 months. In addition, to avoid interfering with ongoing transmission expansion efforts in some transmission planning regions, MISO argues that the Commission should allow such regions to propose their own compliance date or instead should state that the final rule would not apply to any such ongoing transmission expansion efforts, including MISO's Long-Range Transmission Planning initiative.[3715] Additionally, MISO requests that the new rule and tariff revisions complying with the final rule be made effective upon the Commission's acceptance of the filing party's compliance filing.[3716]

1764. PJM states that it would be more efficient and less confusing if PJM could first build the long-term model and then comply with the selection and cost allocation requirements at a later date. PJM therefore requests that the Commission clarify whether it is necessary for transmission providers to develop compliance procedures with respect to selection and cost allocation of transmission projects to be selected through Long-

[3713] NARUC Initial Comments at 50-51.

[3714] Idaho Power Initial Comments at 14; ISO-NE Initial Comments at 41.

[3715] MISO Initial Comments at 90-92.

[3716] *Id.* at 90-91; MISO Reply Comments at 32.

Term Regional Transmission Planning before they have had a chance to create and finalize their long-term transmission planning processes.[3717]

1765. MISO asserts that the Commission should allow a separate and longer compliance period for the interregional transmission coordination requirements.[3718]

1766. Separately, MISO states that while the NOPR indicates that the Commission might permit regional flexibility in some areas, it adopts the "consistent with or superior to" legal standard for evaluating proposed deviations on compliance.[3719] MISO argues that this standard is too inflexible to achieve the Commission's objectives because it neither recognizes the independent nature of RTOs/ISOs nor has a built-in mechanism to acknowledge legitimate regional differences.[3720] Therefore, MISO recommends that the Commission instead apply a version of the "independent entity" variation standard to RTOs/ISOs or otherwise make clear that the proposed reforms contemplate regional flexibility to allow RTOs to retain their best transmission planning practices, particularly those RTOs that are "early movers" of the types of reforms in the NOPR.[3721] If the

[3717] PJM Initial Comments at 98-104.

[3718] MISO Initial Comments at 89.

[3719] MISO Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 74-75).

[3720] MISO Initial Comments at 21-22; MISO Reply Comments at 5.

[3721] MISO Reply Comments at 4. For example, MISO states that its MVP and Long-Range Transmission Plan processes are broadly consistent with the principles and goals of the NOPR and some of its specific proposals, including development of multiple futures, review of various benefit metrics, and use of a 20-year transmission planning horizon. MISO states that repeating the extensive stakeholder effort involved in developing these processes to comply with the new requirements would stall its

Commission decides not to adopt the independent entity variation standard for this final rule, MISO urges the Commission to clarify that it will recognize as "consistent with or superior to" any existing regional transmission planning processes that are substantially equivalent to the proposed requirements to avoid impeding progress already made, while compelling reform in transmission planning regions where needed.[3722]

1767. ISO-NE and ISO RTO Council argue that flexibility should extend to determining the rules for inclusion in the tariff, with implementation details in planning procedures or guides, consistent with the Commission's "rule of reason" standard.[3723]

### C. Commission Determination

1768. We adopt the NOPR proposal, with modification, and require each transmission provider to submit a compliance filing within ten months of the effective date of this final rule revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets all of the requirements adopted in this final rule, except those adopted in the Interregional Transmission Coordination section of this final rule. In response to comments from NARUC, Idaho Power, ISO-NE, and MISO requesting a longer compliance timeline, we find that requiring a ten-month compliance period instead of the eight-month compliance period proposed in the NOPR will allow transmission providers to fully develop proposals to comply with this final rule and allow

momentum. MISO Initial Comments at 10.

[3722] MISO Initial Comments at 25; MISO Reply Comments at 8-9.

[3723] ISO-NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8-9 (citing *City of Cleveland v. FERC*, 773 F.2d. at 1376).

stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. As discussed in the Implementation of Long-Term Regional Transmission Planning section, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles). Therefore, transmission providers in each transmission planning region must propose an effective date for the OATT revisions necessary to comply with this final rule that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle. However, transmission providers may propose an earlier effective date for some or all parts of their revised OATTs to allow them to begin implementing any aspects of the required reforms sooner than the one-year deadline to commence the first Long-Term Regional Transmission Planning cycle.

1769. We deny PJM's request for clarification to allow a later compliance deadline for the selection and cost allocation requirements of this final rule and find it appropriate to require that transmission providers submit a compliance filing that addresses all the requirements of this final rule within ten months of the effective date of this final rule, with the exception of the requirements related to interregional transmission coordination, as previously noted.

1770. In response to MISO's request for a separate, longer compliance timeline for the interregional transmission coordination requirements, we also modify the NOPR proposal and require each transmission provider to submit a separate compliance filing within 12 months of the effective date of this final rule revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final rule.[3724] We find that the additional time to comply with the interregional transmission coordination requirements will allow transmission providers to coordinate with the transmission providers in each of their neighboring transmission planning regions to develop interregional transmission coordination proposals.

1771. Additionally, we adopt the proposed requirement that transmission providers that are not public utilities must adopt the requirements of this final rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[3725]

1772. In this final rule, we make no changes to the standards used to judge requested variations, as described in Order Nos. 888, 2000, 890, and 1000.[3726] Accordingly, we

[3724] *See supra* Interregional Transmission Coordination section.

[3725] NOPR, 179 FERC ¶ 61,028 at P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63).

[3726] Order No. 1000, 136 FERC ¶ 61,051 at P 815; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769-70.

decline to grant MISO's request that the Commission apply the independent entity variation standard, rather than the "consistent with or superior to" standard, for proposed deviations from the requirements in this final rule on compliance. Consistent with the Commission's findings in Order No. 890, we will continue to apply the "consistent with or superior to" standard in the context of transmission planning.[3727]

1773. Regarding MISO's request for clarification, we decline to clarify as part of this final rule that any existing transmission planning processes are consistent with or superior to the requirements in this final rule. Rather, it is more appropriate for a transmission provider to submit such a request as part of its compliance filing, in which the transmission provider must demonstrate that any deviation from the requirements of this final rule, including any existing processes and/or OATT provisions, are consistent with or superior to the requirements of this final rule. Similarly, to the extent that a transmission provider believes that it already complies with any of the requirements of this final rule, it should describe in its compliance filing how the relevant requirements are satisfied, including by referencing specific tariff sheets already on file with the Commission.

1774. In response to ISO-NE's and ISO RTO Council's comment that the final rule should provide flexibility as to which implementation details should be included in planning procedures or guides consistent with the Commission's "rule of reason" standard, we note that the Commission has broad discretion in applying the rule of reason

[3727] Order No. 890, 118 FERC ¶ 61,119 at P 160.

policy,[3728] under which provisions that "significantly affect rates, terms, and conditions" of service, are realistically susceptible of specification, and are not generally understood in a contractual agreement, must be included in the tariff. The tariff need not include "mere implementation details,"[3729] which instead may be included only in the business practice manuals. "[E]ven specifiable practices that significantly affect rates need not be included if they are clearly implied by the tariff's express terms."[3730] The final rule specifies with respect to each requirement the information that must be incorporated into the transmission provider's OATT. We find that the requirements in this final rule regarding what information transmission providers must specify in their tariff on compliance is consistent with the Commission's rule of reason policy.

## XII. Information Collection Statement

1775. The information collection requirements contained in this final rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[3731] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[3732] Upon approval of a

[3728] *Hecate Energy Greene Cnty. 3 LLC v. FERC*, 72 F.4th at 1314 (citing *City of Cleveland v. FERC*, 773 F.2d at 1376 (the FPA's "amorphous" requirement that tariffs include "practices affecting rates" means that the Commission has "broad discretion" in giving the act "concrete application.")).

[3729] *Id.* at 1312.

[3730] *Id.* at 1314 (citing *City of Cleveland v. FERC*, 773 F.2d at 1376).

[3731] 44 U.S.C. 3507(d).

[3732] 5 CFR 1320.11.

collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this final rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

1776. The reforms adopted in this final rule revise the Commission's *pro forma* OATT to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements to ensure that Commission-jurisdictional rates and practices are just and reasonable and not unduly discriminatory or preferential.

1777. In the NOPR, the Commission solicited comments on: the Commission's need for this information; whether the information will have practical utility; the accuracy of the burden estimates; ways to enhance the quality, utility, and clarity of the information to be collected or retained; and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission received one comment from PJM specifically about the time and effort required to comply with the information collection requirement.[3733]

1778. PJM claims that the Commission significantly underestimates the cost for PJM and other transmission providers to comply with the final rule. PJM states that its compliance will require additional staff of between seven to 14 new staff members and that the added cost will be at least $2.1 million per year. However, PJM adds that it

[3733] PJM Initial Comments at 10, 125-29.

generally supports the proposed reforms in the NOPR and provides this information only to give the Commission a better understanding of the time and costs associated with implementing the final rule.[3734]

1779. In response to PJM's comments on the NOPR, we note that this information collection statement estimates the burdens[3735] to generate, maintain, retain, or disclose or provide information to or for a federal agency. In light of the information that PJM supplied, we have revised the table below to increase the estimated amount of labor required for a transmission provider to perform Long-Term Regional Transmission Planning.[3736] We expect that the information collection requirements associated with updating these datasets for subsequent cycles will entail substantially less effort than the initial Long-Term Regional Transmission Planning cycle.

1780. Summary of the Revisions to the Collection of Information due to the final rule in Docket No. RM21-17-000:

- Title: Electric Transmission Facilities (FERC-917).[3737]

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[3734] *Id*. at 128-29.

[3735] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR 1320.3(b)(1).

[3736] For example, for an entire transmission planning region, we anticipate that 10 people each working 2,000 hours per year would spend 20,000 hours per year to develop these datasets.

[3737] In the NOPR, in addition to proposing to revise the FERC-917 information collection, the Commission proposed to revise the *pro forma* LGIP and, therefore, to revise the FERC-516 information collection (Reform of Generator Interconnection

- Action: Revision of collections of information in accordance with Docket No. RM21-17-000.
- OMB Control Nos.: 1902-0233 (FERC-917).
- Respondents: Transmission providers, including RTOs/ISOs.
- Frequency of Information Collection: One time during Year 1. Occasional times during subsequent years, at least once every five years.
- Necessity of Information: The reforms in this final rule will correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.
- Internal Review: We have reviewed the reforms and have determined that such reforms are necessary. These reforms conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.
- Public Reporting Burden: The burden and cost estimates below are based on the need for applicable entities to revise documentation, already required by the Commission's *pro forma* OATT. Our estimates are based on the North American Electric Reliability Corporation Compliance Registry as of January 11, 2024,

Procedures and Agreements). In this final rule, we decline to revise the *pro forma* LGIP, and therefore we are not revising the FERC-516 information collection.

which indicates that there are 48 transmission service providers[3738] with OATTs and 118 transmission owners that are registered within the United States and are subject to this rulemaking.[3739] Because 41 of the 118 transmission owners are also included in the count of 48 transmission service providers, there are 125 distinct entities (i.e., 125 distinct transmission providers[3740]) in total that must comply this final rule. We note that, for the purposes of regional transmission planning, these 125 entities are grouped into 11 transmission planning regions.

1781. We estimate that the final rule would affect the burden and cost of FERC-917 as follows:

| **Changes Due to Final Rule in Docket No. RM21-17-000[3741]** | | | | |
|---|---|---|---|---|
| **A. Area of Modification** | **B. Annual Number of Respondents** | **C. Total Annual Estimated Number** | **D. Average Burden Hours & Cost[3742] per Response** | **E. Total Estimated Burden Hours & Total Estimated Cost** |

[3738] The transmission service provider (TSP) function is a North American Electric Reliability Corporation registration function, which is similar to the transmission provider that is referenced in the *pro forma* OATT. The TSP function is being used as a proxy to estimate the number of transmission providers that are impacted by this proposed rulemaking.

[3739] The number of entities listed from the North American Electric Reliability Corporation Compliance Registry reflects the omission of the Texas registered entities. Note that the 48 transmission providers with OATTs do not include non-public utility transmission providers with reciprocity tariffs.

[3740] *See supra* note 2.

[3741] In the table, Year 1 figures are one-time implementation hours and cost. "Subsequent years" show ongoing burdens and costs starting in Year 2.

[3742] The hourly cost (for salary plus benefits) uses the figures from the Bureau of

| | | of Responses | | (Column C x Column D) |
|---|---|---|---|---|
| **FERC-917, Electric Transmission Facilities (OMB Control No. 1902-0233)** | | | | |
| Draft OATT revisions to comply with the requirements of the final rule | 48 transmission providers with OATTs | 48 | One Time: 770 hours; $71,683<br><br>Ongoing: 0 hours per year; $0 per year | One Time: 36,960 hours; $3,440,783<br><br>Ongoing: 0 hours per year; $0 per year |
| Establish a six-month time period during which transmission providers must, among other things, provide a forum for negotiation that enables participation by Relevant State Entities and to discuss potential Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process. | 48 transmission providers with OATTs | 48 | One Time: 390 hours; $36,307<br><br>Ongoing: 0 hours per year; $0 per year | One Time: 18,720 hours; $1,742,734<br><br>Ongoing: 0 hours per year; $0 per year |
| Participate in Long-Term Regional Transmission Planning, which includes creating and updating datasets, developing Long-Term Scenarios, evaluating the benefits of Long-Term Regional Transmission Facilities, | 48 transmission providers with OATTs | 48 | One Time: 0 hours; $0<br><br>Ongoing: 4,500 hours per year; $418,926 per year | One Time: 0 hours; $0<br><br>Ongoing: 216,000 hours per year; $20,108,471 per year |

Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2022, issued April 25, 2023, http://bls.gov/oes/current/naics2_22.htm) and benefits (based on BLS data for September 2023; issued December 15, 2023, http://www.bls.gov/news.release/ecec.nr0.htm) and are Manager (Occupation Code 11-0000, $122.48/hour), Electrical Engineer (Occupation Code 17-2071, $89.04/hour), and File Clerk (Occupation Code 43-4071, $42.43/hour). The hourly cost for the reporting requirements ($105.76) is an average of the hourly cost (wages plus benefits) of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

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| and establishing criteria in consultation with Relevant State Entities and stakeholders to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation. | 77 transmission providers without OATTs | 77 | One Time: 0 hours; $0<br><br>Ongoing: 200 hours per year; $18,619 | One Time: 0 hours; $0<br><br>Ongoing: 15,400 hours per year; $1,433,659 per year |
| Revise the regional transmission planning process to enhance transparency of local transmission planning and identifying potential opportunities to right-size replacement transmission facilities. | 48 transmission providers with OATTs | 48 | One Time: 30 hours; $2,793<br><br>Ongoing: 120 hours per year; $11,172 per year | One Time: 1,440 hours; $134,056<br><br>Ongoing: 5,760 hours per year; $536,226 per year |
| | 77 transmission providers without OATTs | 77 | One Time: 20 hours; $1,862<br><br>Ongoing: 40 hours per year; $3,724 per year | One Time: 1,540 hours; $143,366<br><br>Ongoing: 3,080 hours per year; $286,732 per year |
| Evaluate whether certain alternative transmission technologies can meet the transmission needs identified in Order No. 1000 regional transmission planning processes and in Long-Term Regional Transmission Planning process more efficiently or cost-effectively than transmission facilities without such alternative transmission technologies. | 48 transmission providers with OATTs | 48 | One Time: 0 hours; $0<br><br>Ongoing: 100 hours per year; $9,309 per year | One Time: 0 hours; $0<br><br>Ongoing: 4,800 hours per year; $446,855 per year |
| | 77 transmission providers without OATTs | 77 | One Time: 0 hours; $0<br><br>Ongoing: 20 hours per year; $1,862 per year | One Time: 0 hours; $0<br><br>Ongoing: 1540 hours per year; $143,366 per year |
| Consider in the Order No. 1000 regional transmission planning processes regional transmission facilities that address certain | 48 transmission providers with OATTs | 48 | One Time: 0 hours; $0<br><br>Ongoing: 50 hours per year; $4,655 per year | One Time: 0 hours; $0<br><br>Ongoing: 2,400 hours per year; $223,427 per year |

| | | | | |
|---|---|---|---|---|
| interconnection-related needs. | | | | |
| Share with the transmission providers in neighboring transmission planning regions information regarding Long-Term Transmission Needs and potential transmission facilities to meet those needs; identify and jointly evaluate interregional transmission facilities with the transmission providers in neighboring transmission planning regions; and publicly post certain information regarding interregional coordination processes applied to Long-Term Regional Transmission Planning. | 48 transmission providers with OATTs | 48 | One Time: 0 hours; $0<br><br>Ongoing: 25 hours per year; $2,327 per year | One Time: 0 hours; $0<br><br>Ongoing: 1,200 hours per year; $111,714 per year |
| **Total burden for the revisions of FERC 917 due to RM21-17** | 48 transmission providers with OATTs | 48 | One Time: 1,190 hours; $110,783<br><br>Ongoing: 4,795 hours per year; $446,390 per year | One Time: 57,120 hours; $5,317,573<br><br>Ongoing: 230,160 hours per year; $21,426,693 per year |
| | 77 transmission providers without OATTs | 77 | One Time: 20 hours; $1,862<br><br>Ongoing: 260 hours per year; $24,205 per year | One Time: 1,540 hours; $143,366<br><br>Ongoing: 20,020 hours per year; $1,863,757 per year |
| | Totals for all 125 transmission providers | | | One Time: 58,660 hours; $5,460,939<br><br>Ongoing: 250,180 hours per year; $23,290,450 per year |

1782. Our estimates conservatively assume the maximum number of respondents and burdens. We acknowledge that the actual burdens for some respondents may be lower than estimated and that other respondents may incur the maximum burdens.

1783. Interested persons may obtain information on the reporting requirements by contacting Jean Sonneman, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 via email (DataClearance@ferc.gov) or telephone (202) 502-8663.

## XIII. Environmental Analysis

1784. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[3743] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final rule under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[3744]

[3743] *Regulations Implementing the Nat'l Env'l Pol'y Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[3744] 18 CFR 380.4(a)(15).

## XIV. Regulatory Flexibility Act

1785. The Regulatory Flexibility Act of 1980 (RFA)[3745] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[3746] RTOs/ISOs, transmission planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 950 employees (including the entity and its associates).[3747]

1786. We have determined that the entities impacted by this final rule are transmission providers in transmission planning regions that span across the United States.[3748]

1787. To identify small firms among the transmission providers that comprise the transmission planning regions, we created a list of transmission service providers and transmission owners from the North American Electric Reliability Corporation Registry (dated January 11, 2024), totaling 125 entities. We conducted research using both open-

[3745] 5 U.S.C. 601-612.

[3746] 13 CFR 121.201.

[3747] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The SBA's regulations define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 950 employees. 13 CFR 121.201; *see* 5 U.S.C. 601(3) (citing section 3 of the Small Business Act, 15 U.S.C. 632).

[3748] *See* FERC, *Regions Map Printable Version Order No. 1000* (Nov. 9, 2021), https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

source information and data from paid services such as Dunn & Bradstreet. We find that, out of the population of 125 transmission providers, 18 would be considered small using the SBA threshold (14% rounded). Therefore, we do not consider this number of small entities to be substantial.

1788. As shown in the table above, we estimate the one-time costs associated with the final rule to be $110,783 per transmission provider with an OATT and $1,862 per transmission provider without an OATT. We estimate the ongoing costs in subsequent years to be $446,390 per year for transmission providers with an OATT and $24,205 per year for transmission providers without an OATT. Further, we note that Commission regulations allow for transmission providers to fully recover the costs of participating in the regional transmission planning process.[3749] Therefore, we do not believe that this cost is economically significant. Accordingly, we certify that the reforms in this final rule will not have a significant economic impact on a substantial number of small entities.

## XV. Document Availability

1789. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov).

1790. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

[3749] Order No. 890, 118 FERC ¶ 61,119 at P 586.

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1791. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

## XVI. Effective Date and Congressional Notification

1792. These regulations are effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Chairman Phillips and Commissioner Clements are concurring with a joint separate statement attached.
Commissioner Christie is dissenting with a separate statement attached.

( S E A L )

Debbie-Anne A. Reese,
Acting Secretary.

**NOTE:** The following appendices will not appear in the Code of Federal Regulations.

## Appendix A: Abbreviated Names of Commenters

### Abbreviated Names of Commenters

| Abbreviation | Commenter(s) |
|---|---|
| Acadia Center and CLF | Acadia Center and Conservation Law Foundation |
| ACEG | Americans for a Clean Energy Grid |
| ACORE | American Council on Renewable Energy |
| Advanced Energy Buyers | Advanced Energy Buyers Group |
| AEE | Advanced Energy Economy |
| AEP | American Electric Power Service Corporation |
| Alabama Commission | Alabama Public Service Commission |
| Amazon | Amazon Energy LLC |
| Ameren | Ameren Services Company |
| American Municipal Power | American Municipal Power, Inc. |
| Americans for Fair Energy Prices | Americans for Fair Energy Prices, Inc. |
| Anbaric | Anbaric Development Partners, LLC |
| APPA | American Public Power Association |
| APS | Arizona Public Service Company |
| Arizona Commission | Arizona Corporation Commission |
| ATC | American Transmission Company LLC |
| Avangrid | Avangrid, Inc. |
| Bekaert | Bekaert Corporation |
| BP | bp America |
| Breakthrough Energy | Breakthrough Energy |
| Business Council for Sustainable Energy | Business Council for Sustainable Energy |
| CAISO | California Independent System Operator Corporation |
| California Commission | California Public Utilities Commission |
| California Democratic Representatives | US Representatives Jared Huffman; Mike Levin; Nanette Diaz Barragán; Grace F. Napolitano; Anna G. Eshoo; Katie Porter; Judy Chu; Mike Thompson; Ted W. Lieu; Julia Brownley; Mark DeSaulnier; and Juan Vargas |
| California Energy Commission | California Energy Commission |

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|---|---|
| California Municipal Utilities | California Municipal Utilities Association |
| California Water | California Department of Water Resources State Water Project |
| CARE Coalition | The National Audubon Society; Defenders of Wildlife; Environmental Law & Policy Center; National Wildlife Federation; The Nature Conservancy; Center for Renewables Integration; and Vote Solar, jointly the Conservation and Renewable Energy Coalition |
| Center for Biological Diversity | The Center for Biological Diversity |
| Ceres | Ceres |
| Certain TDUs | Alliant Energy Corporate Services, Inc.; Consumers Energy Company; and DTE Electric Company |
| Chemistry Council | American Chemistry Council |
| Citizens Energy | Citizens Energy Corporation |
| City of New Orleans Council | Council of the City of New Orleans |
| City of New York | City of New York |
| Clean Energy Associations | The American Clean Power Association; Alliance for Clean Energy-New York; Clean Grid Alliance; the Mid-Atlantic Renewable Energy Council Action; and the New York Offshore Wind Alliance, collectively Clean Energy Associations |
| Clean Energy Buyers | Clean Energy Buyers Association |
| Clean Energy States | Clean Energy States Alliance |
| Colorado Consumer Advocate | Colorado Office of the Utility Consumer Advocate |
| Competition Advocates | Niskanen Center; R Street Institute; Institute for Local Self Reliance; Public Citizen, Inc.; Center for Biological Diversity; and Open Markets Institute |
| Competition Coalition | Electricity Transmission Competition Coalition |
| Concerned Scientists | The Union of Concerned Scientists |
| Conservative Energy Network | Conservative Energy Network |
| Conservatives for Clean Energy – Florida | Conservatives for Clean Energy – Florida |
| Conservatives for Clean Energy – SC | Conservatives for Clean Energy - South Carolina |
| Consumer Organizations | NJ Charge, Inc.; Keryn Newman (Stop Path WV); Illinois Landowners Alliance; Block Grain Belt Express-Missouri; Citizens to Stop Transource - York; Coalition for Rural Property Rights; Eastern Missouri Landowners Alliance; Missouri Landowners Association; Protect Sudbury Inc.; Say No to |

| | |
|---|---|
| Cross Sector Representatives | NECEC; Stop B2H Coalition; Eastern Missouri Landowners Alliance; SOUL of Wisconsin; Block RICL; Matthew Stallbaumer; Vickie Husbands; Elena Guardincerri; Martha Peine; Kerry Beheler; Barron Shaw; and STOP Transource Power Lines MD, Inc. Ameren Transmission; Blue-Green Alliance; Consolidated Edison Company of New York, Inc.; Edison International; Exelon Corporation; Greater Warren County Economic Development Council; International Brotherhood of Electric Workers IBEW 1245; IBEW Illinois State Conference; IBEW International; IBEW Sixth District; ITC Holdings Corp.; National Audubon Society; Pacific Gas & Electric Co.; The Permitting Institute; Public Service Electric and Gas Company; WEG Transformers USA; and Xcel Energy |
| CTC Global | CTC Global Corporation |
| Cypress Creek | Cypress Creek Renewables, LLC |
| DATA | Ameren Services Company; Eversource Energy; Exelon Corporation; ITC Holdings Corp.; National Grid USA; Public Service Electric and Gas Company; and Xcel Energy; collectively Developers Advocating Transmission Advancements (DATA) |
| DC and MD Offices of People's Counsel | The Office of the People's Counsel for the District of Columbia and the Maryland Office of People's Counsel |
| Dominion | Dominion Energy Services, Inc |
| Duke | Duke Energy Corporation |
| Duquesne Light | Duquesne Light Company |
| EEI | Edison Electric Institute |
| ELCON | Electricity Consumers Resource Council |
| Enel | Enel North America, Inc. |
| ENGIE | ENGIE North America, Inc. |
| Entergy | Entergy Services, LLC |
| Environmental Groups | Advanced Energy United; American Clean Power Association; Clean Air Task Force; Earthjustice; Environmental Defense Fund; Evergreen Action; Fresh Energy; Interwest Energy Alliance; League of Conservation Voters; National Wildlife Federation; Natural Resources Defense Council; Northwest Energy Coalition; Rewiring America; Sierra Club; |

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| | Southern Environmental Law Center; The Environmental Law & Policy Center; Union of Concerned Scientists; WE ACT for Environmental Justice; and Western Resource Advocates |
| Environmental Legislators Caucus | National Caucus of Environmental Legislators |
| EPSA | Electric Power Supply Association |
| Evergreen Action | Evergreen Action and 4,440 Individual Signers |
| Eversource | Eversource Energy Service Company |
| Exelon | Exelon Corporation |
| Fervo | Fervo Energy Company |
| Form Energy | Form Energy, Inc. |
| Freeport-McMoRan | Freeport-McMoRan, Inc. |
| Georgia Commission | Georgia Public Service Commission |
| Governor of Kansas Laura Kelly | Governor of the State of Kansas Laura Kelly |
| Grand Rapids NAACP | Greater Grand Rapids Chapter of The National Association for the Advancement of Colored People |
| Grid United | Grid United LLC |
| GridLab | GridLab |
| Handy Law | Seth Handy, Handy Law, LLC |
| Hannon Armstrong | Hannon Armstrong Sustainable Infrastructure Capital, Inc. |
| Harvard ELI | Harvard Electricity Law Initiative |
| Idaho Commission | The Idaho Public Utilities Commission |
| Idaho Power | Idaho Power Company |
| Illinois Commission | The Illinois Commerce Commission |
| Indiana Commission | Indiana Utility Regulatory Commission |
| Indicated PJM TOs | The Dayton Power and Light Company; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, West Penn Power Company, The Potomac Edison Company, Monongahela Power Company, Keystone |

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| | Appalachian Transmission Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; Rockland Electric Company; and UGI Utilities Inc. |
| Indicated US Senators and Representatives | US Senators Tina Smith; Edward J. Markey; and Sheldon Whitehouse; US Representatives Kathy Castor; Bobby L. Rush; Paul Tonko; Sean Casten; Raja Krishnamoorthi; Jared Huffman; Veronica Escobar; and Julia Brownley |
| Industrial Customers | American Forest & Paper Association; the PJM Industrial Customer Coalition; and the Coalition of MISO Transmission Customers, collectively the Industrial Customer Organizations |
| Interwest | Interwest Energy Alliance |
| Invenergy | Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; and Invenergy Transmission LLC |
| Iowa Commission | Iowa Utilities Board |
| ISO/RTO Council | The ISO/RTO Council |
| ISO-NE | ISO New England Inc. |
| ITC | International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC |
| Joint Commenters | American Public Power Association; Electricity Consumers Resource Council; Indiana Office of Utility Consumer Counselor; Large Public Power Council; National Association of State Utility Consumer Advocates; Office of People's Counsel for the District of Columbia; Public Advocate for the State of Delaware; and Solar Energy Industries Association |
| Joint Consumer Advocates | Iowa Office of Consumer Advocate and Indiana Office of Utility Consumer Counselor |
| Kansas Commission | Kansas Corporation Commission |
| Kansas Commission Chair Keen | Kansas Corporation Commission Chairman Dwight D. Keen |
| Kansas Ratepayers Advocates | Kansas Industrial Consumers Group, Inc. and Kansans for Lower Electric Rates, Inc. |
| Kentucky Commission Chair Chandler | Kentucky Public Service Commission Chairman and |

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| | Commissioner Kent A. Chandler |
| LADWP | Los Angeles Department of Water & Power |
| Large Energy Customers | Akamai Technologies, Inc.; Amazon.com, Inc.; Amy's Kitchen, Inc.; Apple, Inc.; Applied Materials, Inc.; ARC Homes; Atlassian Corporation; Autodesk, Inc.; BASF Corporation; Best Buy Co., Inc.; Brookfield Properties; Budderfly, Inc.; Build Efficiently, LLC.; Cargill, Inc.; Clean Energy Buyers Association; Eastman Chemical Company; eBay, Inc.; Equinix, Inc.; Freeport-McMoRan, Inc.; General Motors LLC; Google LLC; Green Impact Technologies; Hewlett Packard Enterprise Company; Humanscale Corporation; IHG Hotels & Resorts; Marriott International, Inc.; Mars, Inc.; Meta Platforms, Inc.; Microsoft Corporation; Monarch Energy; Nike, Inc.; Nucor Corporation; Oatly Group AB; PepsiCo, Inc.; Prologis, Inc.; Rivian Automotive, Inc.; Saint-Gobain North America; Salesforce, Inc.; Schneider Electric SE; Target Corporation; Thermo Fisher Scientific, Inc.; The STAAC Group; LLC., Walmart, Inc.; Workday, Inc.; and World Energy, LLC. |
| Large Public Power | The Large Public Power Council |
| Louisiana Commission | Louisiana Public Service Commission |
| LS Power | LS Power Grid, LLC |
| Maine Public Advocate | The Maine Office of the Public Advocate |
| Maryland Energy Administration | Maryland Energy Administration |
| Massachusetts Attorney General | Massachusetts Attorney General Maura Healey |
| Michigan Commission | Michigan Public Service Commission |
| Michigan Conservative Energy Forum | Michigan Conservative Energy Forum |
| Michigan State Entities | Michigan Attorney General and the Citizens Utility Board of Michigan |
| Microgrid Resources | Microgrid Resources Coalition |
| Middle River Power | Middle River Power LLC |
| Minnesota State Entities | The Minnesota Public Utilities Commission and The Minnesota Department of Commerce |
| MISO | Midcontinent Independent System Operator, Inc. |
| MISO Coops | The Coalition of MISO Generation and Transmission Cooperatives |
| MISO TOs | Ameren Services Company, as agent for Union |

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| | Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc. |
| Mississippi Commission | The Mississippi Public Service Commission |
| Montana QF Developers | Clēnera, LLC and Greenfields Irrigation District |
| Montclair Congregation | 40 Undersigned Congregants of Montclair Presbyterian Church |
| NARUC | The National Association of Regulatory Utility Commissioners |
| NASEO | The National Association of State Energy Officials |
| NASUCA | The National Association of State Utility Consumer Advocates |
| National and State Conservation Organizations | National Wildlife Federation; Conservation Coalition of Oklahoma; Environment Council of Rhode Island; Environmental League of Massachusetts; Idaho Wildlife Federation; Iowa Wildlife Federation; Kentucky Waterways Alliance; Natural Resources Council of Maine; Nevada Wildlife Federation; New |

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| | Jersey Audubon; Southeast Alaska Conservation Council; Texas Conservation Alliance; Utah Wildlife Federation; WV Rivers Coalition; and Wyoming Wildlife Federation |
| National Grid | National Grid Plc |
| Nebraska Commission | The Nebraska Power Review Board |
| NEMA | National Electrical Manufacturers Association |
| NEPOOL | The New England Power Pool Participants Committee |
| NERC | North American Electric Reliability Corporation; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation, Texas Reliability Entity, Inc., and Western Electricity Coordinating Council |
| NESCOE | The New England States Committee on Electricity |
| Nevada Commission | The Public Utilities Commission of Nevada |
| New England for Offshore Wind | New England for Offshore Wind |
| New England Systems | Belmont Municipal Light Department; Block Island Utility District; Braintree Electric Light Department; Chicopee Municipal Light Department; Georgetown Municipal Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; North Attleborough Electric Department; Norwood Municipal Light Department; Pascoag Utility District; Reading Municipal Light Department; Stowe Electric Department; Taunton Municipal Lighting Plant; Wallingford Electric Division; and Westfield Gas & Electric Light Department |
| New Jersey Commission | The New Jersey Board of Public Utilities |
| New Mexico RETA | The New Mexico Renewable Energy Transmission Authority |
| New York Commission and NYSERDA | New York Public Service Commission and New York State Energy Research and Development Authority |
| New York State Department | New York State Department of State Utility Intervention Unit |
| New York TOs | Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; |

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| | Niagara Mohawk Power Corporation; New York Power Authority; New York State Electric & Gas Corporation; Orange and Rockland Utilities, Inc.; Long Island Power Authority; and Rochester Gas and Electric Corporation |
| New York Transco | New York Transco, LLC |
| NextEra | NextEra Energy, Inc |
| Non-RTO NASUCA | North Carolina Utilities Commission Public Staff; the Utah Office of Consumer Service; the South Carolina Office of Regulatory Staff; and the Wyoming Office of Consumer Advocate |
| North Carolina Commission and Staff | The North Carolina Utilities Commission and the North Carolina Utilities Commission Public Staff |
| North Dakota Commission | North Dakota Public Service Commission Public Utilities Division |
| Northwest and Intermountain | Northwest & Intermountain Power Producers Coalition |
| NRECA | National Rural Electric Cooperative Association |
| NRG | NRG Energy, Inc |
| NYISO | New York Independent System Operator, Inc. |
| NYPA | New York Power Authority |
| Ohio Commission Federal Advocate | The Public Utilities Commission of Ohio's Office of the Federal Energy Advocate |
| Ohio Conservative Energy Forum | Ohio Conservative Energy Forum |
| Ohio Consumers | Office of The Ohio Consumers' Counsel |
| Omaha Public Power | The Omaha Public Power District |
| OMS | The Organization of Midcontinent Independent System Operator States, Inc. |
| Onward Energy | Onward Energy Holdings, LLC |
| Ørsted | Ørsted North America |
| Pacific Northwest State Agencies | The Washington Utilities and Transportation Commission; Oregon Public Utility Commission; Washington State Department Of Commerce; and Oregon Department Of Energy |
| Pacific Northwest Utilities | Avista Corporation; Portland General Electric; Puget Sound Energy, Inc.; and Tacoma Power |
| PacifiCorp and NV Energy | PacifiCorp; Nevada Power Company and Sierra Pacific Power Company (together, NV Energy) |
| Pattern Energy | Pattern Energy Group LP |
| Payton Alaama | Payton Alaama |

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| Pennsylvania Commission | The Pennsylvania Public Utility Commission |
| PG&E | Pacific Gas and Electric Company |
| Pine Gate | Pine Gate Renewables, LLC |
| PIOs | Sustainable FERC Project; Natural Resources Defense Council; Sierra Club; Environmental Defense Fund; Southern Environmental Law Center; Conservation Law Foundation; Western Resource Advocates; Acadia Center; NW Energy Coalition; Southface Institute; and Fresh Energy, jointly Public Interest Organizations |
| PJM | PJM Interconnection, L.L.C. |
| PJM Market Monitor | The Independent Market Monitor of PJM Interconnection, L.L.C. |
| PJM States | The Organization of PJM States, Inc. (OPSI) |
| Policy Integrity | The Institute for Policy Integrity at New York University School of Law |
| Potomac Economics | Potomac Economics, Ltd. |
| PPL | PPL Electric Utilities Corporation; Louisville Gas & Electric and Kentucky Utilities (collectively LG&E/KU); and The Narragansett Electric Company |
| Prysmian | The Prysmian Group |
| Public Systems | Massachusetts Municipal Wholesale Electric Company; New Hampshire Electric Cooperative, Inc.; Connecticut Municipal Electric Energy Cooperative; and Vermont Public Power Supply Authority |
| QCo | QCoefficient, Inc. |
| R Street | R Street Institute |
| Rail Electrification | The Rail Electrification Council |
| Renewable Northwest | Renewable Northwest |
| Resale Iowa | Resale Power Group of Iowa |
| RMI | RMI |
| SDG&E | San Diego Gas & Electric Company |
| SEIA | The Solar Energy Industries Association |
| SEPA | The Smart Electric Power Alliance |
| SERTP Sponsors | Associated Electric Cooperative, Inc.; Dalton Utilities; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC; Georgia Transmission Corporation; Louisville Gas and Electric Company and Kentucky Utilities Company; the Municipal |

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| | Electric Authority of Georgia; PowerSouth Energy Cooperative; Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company; the Tennessee Valley Authority; and Gulf Power Company, collectively Sponsors of the Southeastern Regional Transmission Planning Process (SERTP) |
| Shell | Shell Energy North America (US), L.P.; Shell New Energies US, LLC; and Savion L.L.C. |
| Signatories | American Council on Renewable Energy; Americans for a Clean Energy Grid; American Clean Power Association; AES Corporation; Advance Energy Economy; Center for Rural Affairs; Clean Air Task Force; Clean Energy Buyers Alliance; Conservative Energy Network; ConEd Transmission, Inc.; Enel North America, Inc.; Exelon Corporation; GE Renewables; Grid United LLC; Google; Holy Cross Energy; Invenergy; ITC Holdings Corp.; Land & Liberty Coalition; Macro Grid Initiative; National Audubon Society; National Electrical Manufacturer Association; National Wildlife Federation; Natural Resources Defense Council; NextEra Energy, Inc.; Northwest & Intermountain Power Producers Coalition; Pattern Energy; Rail Electrification Council; Rocky Mountain Institute (RMI); Sierra Club; Solar Energy Industries of America; and Southern Renewable Energy Association |
| Six Cities | The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California |
| Smart Wires | Smart Wires |
| SoCal Edison | Southern California Edison Company |
| Southeast PIOs | Southern Environmental Law Center; Energy Alabama; North Carolina Sustainable Energy Association; South Carolina Coastal Conservation League; Southface Energy Institute; and Southern Alliance for Clean Energy, jointly Southeast Public Interest Groups |
| Southern | Southern Company Services, Inc. |
| Southwester Power Group | Southwestern Power Group |
| SPP | Southwest Power Pool Inc. |

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| SPP Market Monitor | The Southwest Power Pool Market Monitoring Unit |
| SREA | Southern Renewable Energy Association |
| State Agencies | Connecticut Department of Energy and Environmental Protection; Connecticut Attorney General; Connecticut Office of Consumer Counsel; Connecticut Public Utilities Regulatory Authority; California Energy Commission; Delaware Division of the Public Advocate; Attorney General of the District of Columbia; Maine Office of the Public Advocate; Maryland Attorney General; Massachusetts Attorney General; Michigan Attorney General; Pennsylvania Office of The Consumer Advocate; and the Rhode Island Attorney General |
| State of Tennessee | State of Tennessee |
| State Officials | Maine Governor's Energy Office; Washington State Department of Commerce; Arizona Governor's Office of Resiliency; California Natural Resources Agency; Colorado Energy Office; Deputy Governor of Illinois; Maryland Energy Administration; Michigan Department of Environment, Great Lakes, and Energy; New Mexico Energy Minerals and Natural Resources Department; Office of New York Governor Kathy Hochul; and Office of North Carolina Governor Roy Cooper |
| State Water Contractors | State Water Contractors |
| Tabors Caramanis Rudkevich | Tabors Caramanis & Rudkevich |
| TANC | Transmission Agency of Northern California |
| TAPS | Transmission Access Policy Study Group |
| Transmission Dependent Utilities | Golden Spread Electric Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc., collectively, Transmission Dependent Utility Systems |
| Transource | Transource Energy, LLC |
| Undersigned States [Initial Comments] | Utah Attorney General; Alaska Attorney General; Georgia Attorney General; Idaho Attorney General; Indiana Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; North Dakota Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina |

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| | Attorney General; Texas Attorney General; West Virginia Attorney General; and Wyoming Attorney General |
| Undersigned States [Reply Comments] | Utah Attorney General; Alabama Attorney General; Alaska Attorney General; Arkansas Attorney General; Florida Attorney General; Georgia Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina Attorney General; Texas Attorney General; and West Virginia Attorney General |
| US Chamber of Commerce | U.S. Chamber of Commerce |
| US Climate Alliance | United States Climate Alliance |
| US Democratic Representatives | US Representatives Paul D. Tonko and 112 additional US Representatives |
| US DOE | United States Department of Energy |
| US DOJ and FTC | United States Department of Justice and the Federal Trade Commission |
| US House Republicans | US Representatives Andrew R. Garbarino; Anthony D'Espositio; Nicholas A. Langworthy; and Brandon Williams |
| US Senator Barrasso | US Senator John Barrasso |
| US Senator Heinrich | US Senator Martin Heinrich |
| US Senators | US Senators Martin Heinrich; Edward J. Markey; Peter Welch; John Hickenlooper; Angus S. King, Jr.; Ron Wyden; Robert P. Casey, Jr.; Sheldon Whitehouse; Tina Smith; Ben Ray Luján; Chris Van Hollen; Mazie K. Hirono; Jeffrey A. Merkley; Brian Schatz; Thomas R. Carper; Bernard Sanders; Patty Murray; John Fetterman; Michael F. Bennet; Elizabeth Warren; and Alex Padilla |
| US Senators Heinrich and Lee | US Senators Martin Heinrich and Mike Lee |
| US Senators Hickenlooper and King | US Senators John Hickenlooper and Angus S. King, Jr. |
| US Senator Schumer | US Senator Charles E. Schumer |
| US Senator Whitehouse | US Senator Sheldon Whitehouse |
| Utah Commission | The Utah Public Service Commission |
| Utah Division of Public Utilities | Utah Department of Commerce, Division of Public Utilities |

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| VEIR | VEIR Inc. |
| Vermont Electric and Vermont Transco | Vermont Electric Power Company, Inc., and Vermont Transco LLC |
| Vermont State Entities | The Vermont Public Utility Commission and the Vermont Department of Public Service |
| Virginia Attorney General | Virginia Office of the Attorney General, Division of Consumer Counsel |
| Virginia Commission Staff | The Staff of the Virginia State Corporation Commission |
| Vistra | Vistra Corp. |
| WATT Coalition | The Working for Advanced Transmission Technologies (WATT) Coalition |
| WE ACT | WE ACT for Environmental Justice |
| West Virginia Commission | The Public Service Commission of West Virginia |
| Western PIOs | Center for Energy Efficiency and Renewable Technologies; NW Energy Coalition; Western Resource Advocates; and Renewable Northwest; collectively, Western Public Interest Organizations |
| Western State Representatives | Agency Representatives from the states of Arizona; California; Idaho; Montana; Nevada; Oregon; South Dakota; Utah; Washington; and Wyoming |
| Western Way Colorado | Western Way Colorado |
| Western Way Nevada | Western Way Nevada |
| Western Way Utah | Western Way Utah |
| Wildlife Federation Action Fund Supporters | 8,610 Supporters of the National Wildlife Federation Action Fund |
| WIRES | WIRES |
| Wisconsin Conservative Energy Forum | Wisconsin Conservative Energy Forum |
| Wisconsin Legislators | Wisconsin State Senator Julian Bradley and Wisconsin State Representative David Steffen |
| Wisconsin Senator Cowles | Wisconsin State Senator Robert L. Cowles |
| Xcel | Xcel Energy Services Inc. |

## Appendix B: *Pro Forma* Open Access Transmission Tariff Attachment K

Note: Proposed deletions are in brackets and proposed additions are in italics.

### ATTACHMENT K

### Transmission Planning Process

### Local Transmission Planning

The Transmission Provider shall establish a coordinated, open, and transparent *local transmission* planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open, and transparent *local transmission* planning process shall be provided as an attachment to the Transmission Provider's Tariff. The Transmission Provider's *local transmission* planning process shall *provide stakeholders with meaningful opportunities to participate and provide feedback, and shall* satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new *transmission* projects. The *local transmission* planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The *local transmission* planning process also shall provide a mechanism for the recovery and allocation of *transmission*

planning costs consistent with Order No. 890. The description of the Transmission Provider's *local transmission* planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

**Regional Transmission Planning**

The Transmission Provider shall participate in a regional transmission planning

process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order Nos. 1000 *and 1920*. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as [set out and explained]*established* in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The *description of the* regional transmission planning process *in the Tariff* also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of "*transmission* planning costs" consistent with Order Nos. 890 and *1000*.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning

process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

*The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region. The three meetings must occur before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's transmission planning models. The three stakeholder meetings for local transmission planning information are the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, and the three stakeholder meetings must meet the requirements in Order No. 1920.*

*As part of the regional transmission planning process, the Transmission Providers in each transmission planning region shall conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. As part of this Long-Term Regional Transmission Planning, the Transmission Providers in each*

*transmission planning region shall meet the requirements set forth in Order No. 1920, including: (1) identifying Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. 1920; (2) measuring the required seven benefits consistent with the requirements set forth in Order No. 1920; (3) using the measured benefits to evaluate Long-Term Regional Transmission Facilities; and (4) using selection criteria consistent with the requirements set forth in Order No. 1920 that provide the opportunity for Transmission Providers to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address Long-Term Transmission Needs.*

*The process through which the Transmission Providers in each transmission planning region develop Long-Term Scenarios must comply with the following six transmission planning principles established in Order No. 890: coordination; openness; transparency; information exchange; comparability; and dispute resolution. The Transmission Providers in each transmission planning region shall outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios. The Transmission Providers in each transmission planning region shall also outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be*

*captured through assumptions made in the development of Long-Term Scenarios.*

*The Transmission Providers in each transmission planning region shall include in their Tariffs a general description of how they will measure each of the seven required benefits used to evaluate Long-Term Regional Transmission Facilities. The Transmission Providers in each transmission planning region shall measure and use the seven benefits, as described in Order No. 1920, in Long-Term Regional Transmission Planning.*

*As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall include in their Tariffs an evaluation process, including selection criteria, that: (1) is transparent and not unduly discriminatory; (2) aims to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; (3) seeks to maximize benefits accounting for costs over time without over-building transmission facilities; and (4) otherwise satisfies the requirements set forth in Order No. 1920.*

*The Transmission Providers in each transmission planning region shall include in their Tariffs one or more Long-Term Regional Transmission Cost Allocation Methods, which is an ex ante regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation and that complies with the requirements set forth in Order No. 1920. The Transmission Providers in each transmission planning*

*region may also, subject to (1) the agreement of Relevant State Entities and (2) Commission acceptance, include in their Tariffs a State Agreement Process. A State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. The Tariff must describe how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the transmission provider; and the circumstances under which, or the information necessary for, a transmission provider to file or to consider filing the agreed cost allocation.*

*As part of evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities, the Transmission Providers in each transmission planning region shall consider in all of their regional transmission planning and cost allocation processes whether selecting transmission facilities that incorporate the following technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies: dynamic line ratings, as defined in 18 CFR § 35.28(b)(14), advanced power flow control devices, advanced conductors, and/or transmission switching. Specifically, such consideration must include both: (1) whether incorporating dynamic line ratings, advanced power flow control devices, advanced*

*conductors, and/or transmission switching into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching as part of any potential regional transmission facility would be more efficient or cost-effective. Transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of Order No. 1920.*

*The Transmission Providers in each transmission planning region shall evaluate for potential selection in the regional transmission plan for purposes of cost allocation regional transmission facilities that address interconnection-related transmission needs originally identified through the generator interconnection process. This requirement applies in the existing Order No. 1000 regional transmission planning processes. The Transmission Providers must modify their Tariffs to include these requirements. The interconnection-related transmission needs that Transmission Providers must evaluate in the existing Order No. 1000 regional transmission planning process are those for which:*

*(1) Transmission Providers in the transmission planning region have identified the relevant interconnection-related transmission need in interconnection studies*

*in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the accepted tariff provisions proposed to comply with this reform in Order No. 1920, and the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions);*

*(2) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need has a voltage of at least 200 kV and an estimated cost of at least $30 million;*

*(3) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need is not currently planned to be developed because the interconnection request(s) that led to the identification of the interconnection-related transmission need has been withdrawn; and*

*(4) the Transmission Providers have not identified a different interconnection-related Network Upgrade to meet the relevant interconnection-related transmission need in an executed Generator Interconnection Agreement or in a Generator Interconnection Agreement that the interconnection customer requested that the Transmission Provider file unexecuted with the Commission.*

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the *regional* transmission planning process and seek regional cost allocation;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the *regional* transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources; *and*

[The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order Nos. 1000; and]

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include [a ]cost allocation methods [or methods ]that satisfy the [six regional cost allocation principles]*requirements* set forth in

Order Nos. 1000 *and 1920*.

***Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities***

*As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above a voltage threshold not to exceed 200 kV that an individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs, as discussed in Order No. 1920. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. 1920. The Transmission Providers in each transmission planning region shall include in their Tariffs a cost allocation method for right-sized replacement transmission facilities that are selected in the regional transmission plan for purposes of cost allocation.*

**Interregional Transmission Coordination**

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans *(including information regarding the Long-Term Transmission Needs and potential transmission facilities to meet those needs)* to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are

proposed to be located in both transmission planning regions, *including those that may be more efficient or cost-effective transmission solutions to Long-Term Transmission Needs*;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process, *including:*

*(a) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings;*

*(b) any interregional transmission facilities proposed or identified in response to the Long-Term Transmission Needs;*

*(c) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning;*

*(d) the results of any cost-benefit evaluation of such interregional transmission facilities, with results including both any overall benefits identified, as well as any benefits particular to each transmission planning region; and*

*(e) the interregional transmission facilities, if any, selected in the regional transmission plan for purposes of cost allocation to meet Long-Term Transmission Needs.*

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning

regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation — Docket No. RM21-17-000

(Issued May 13, 2024)

PHILLIPS, Chairman, CLEMENTS, Commissioner, *concurring*:

1. The electric transmission grid is the backbone of the American economy and essential to the national security of our country. The mission of this agency is to ensure reliable, safe, secure, and economically efficient energy for consumers at a reasonable cost. Ensuring we have a robust, well-planned electric transmission grid is the single most important step that this Commission can take to fulfill that statutory mandate. It is a *reliability imperative*. The transmission grid ultimately allows consumers to have access to the electricity they need—when they need it—to power their homes and businesses. It is equally an *affordability imperative*. The transmission grid gives those same consumers access to diverse, low-cost sources of electricity that help ensure energy bills remain just and reasonable. All told, a strong electric transmission grid is the foundation for how this Commission meets its most important statutory responsibilities under the Federal Power Act (FPA).

2. That has never been more true than it is today. We are in the midst of a pivotal moment for the electricity system. As a nation, we are seeing unprecedented demands on the grid from extreme weather, increasing and rapidly changing patterns of electricity use, and fundamental shifts in the resource mix. And there is every reason to believe those trends will continue, and, indeed, accelerate, in the years ahead.

3. At the same time, our transmission grid is old. More than 70 percent of the grid was built over 25 years ago and much of it was put into service in the 1960s and 1970s, when this agency was still the Federal Power Commission. Our country cannot meet the challenges of today, let alone tomorrow, with yesterday's transmission system. And being unprepared to meet those increased demands jeopardizes the safety and security of our grid. Nevertheless, as a country, we have so far failed to make the investments in the types of transmission facilities needed to ensure continued reliability and affordability at anywhere near the scale or speed needed to meet this pivotal moment.

4. The cost of continued inaction is immeasurable. Failure to act now would hamper the reliability and resilience of our electric grid while leaving customers holding the bag for the inevitably more costly upgrades in the future. Indeed, under the status quo, with its de facto emphasis on the piecemeal, just-in-time development of the grid to meet near-term reliability and economic needs, customers are being forced to fund investments that

could have been more beneficial, less costly, or both had they been better planned from the start. That result undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country.

5. Avoiding those costs requires a forward-looking, comprehensive, and holistic transmission planning and cost allocation framework. That framework must consider the diverse challenges facing the transmission grid, identify the solutions that will address those challenges, and ensure only customers who benefit from those facilities pay their share of the cost, while ensuring that customers who do not benefit do not pay. Period.

6. We must conduct this planning and cost allocation on a regional basis and with an aperture consistent with the scope and scale of the challenges we face. That is, after all, why Congress enacted Title II of the FPA: To provide a coherent regional and national regulatory regime and avoid the harms and costs that come from a balkanized electricity system in which every state is its own regulatory island.[1]

7. Today's final rule does just that. We are requiring transmission planners to plan Long-Term Regional Transmission Facilities using the factors we know drive the transmission needs of tomorrow and consider the reliability and affordability benefits those facilities will provide. At the same time, we are giving transmission planners discretion regarding whether and how to select which transmission facilities to build, recognizing no two regions of the country are alike and a one-size-fits-all solution simply will not produce the infrastructure we so badly need.

8. When it comes to the critical question of "who pays," we are providing transmission planners with the maximum flexibility we can legally allow in order to facilitate negotiated, regionally appropriate solutions. And, as part of a multi-pronged approach to protecting customers, we are requiring transmission planners to reevaluate any previously selected Long-Term Regional Transmission Facility when the actual or projected costs of that facility significantly exceed the cost estimates used during selection. Finally, we are also providing states with unprecedented, expanded

[1] *New York v. FERC*, 535 U.S. 1, 6 (2002) ("When it enacted the FPA in 1935, Congress authorized federal regulation of electricity in areas beyond the reach of state power," tasking the Commission's predecessor with "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." (quoting *Gulf States Utils. Co. v. F.P.C.*, 411 U.S. 747, 758 (1973))); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 265-66 (2016) (*EPSA*) (same); *cf. First Iowa Hydro-Elec. Co-op v. F.P.C.*, 328 U.S. 152, 180 (1946) (The Federal Water Power Act of 1920 was "a complete scheme of national regulation which would promote the comprehensive development of the water resources of the Nation, in so far as it was within the reach of the federal power to do so, instead of the piecemeal, restrictive, negative approach of the River and Harbor Acts and other federal laws previously enacted.").

opportunities to work with transmission providers to shape the cost allocation approaches of their regions, while meeting the beneficiary pays requirement that is the foundation of cost causation under the FPA's just and reasonable standard.

## I. The Dissent's Approach Would Not Result in the Energy Infrastructure Buildout We Need

9. Commissioner Christie provides a stark alternative vision in his dissent, one that would violate the cost causation principle and harm electric reliability. While we agree with his emphasis on the importance of cooperation with states—and have created unprecedented opportunities for such cooperation throughout this final rule—his radical new approach would permit a state to receive economic, resilience, and reliability benefits from new energy infrastructure, but not be charged a single cent unless they expressly agree to pay. That myopic view does not satisfy the requirements of the FPA and would not adequately facilitate the development of transmission we desperately need to ensure reliability and affordability. Contrary to the dissent's assertion that this final rule is the product of a political agenda, failing to act based on the dissent's flawed reading of the circumstances through the lens of politics would abdicate the Commission's duty.

10. The dissent's approach would necessarily require the Commission to ignore evidence about which consumers benefit from the increased reliability, resilience, and affordability due to grid expansion. Instead, backbone regional transmission could not be built unless every state unanimously opted into an agreed cost allocation. But for the same reason that passing around a hat is no way to fund the fire department, roads, or bridges, such an approach to building critical, public interest infrastructure that relies entirely on the voluntary contributions of individual states (or could even be defeated by the refusal to contribute by a single state) will not beget the transmission infrastructure needed to maintain reliability and affordability.

11. Put another way, there is little reason to believe that we, as a country, would build the infrastructure needed to power the world's largest economy if individual states that benefit from that infrastructure could simply decline to pay. Instead, Commissioner Christie's approach would be far more likely to result in a failure to make needed investments entirely, or else to down-size those investments in a way that results in exactly the type of piecemeal transmission development that led us to conclude existing transmission planning practices are rendering transmission rates unjust and unreasonable. That result would leave America far worse off. Just as the Articles of Confederation were not a sufficient platform to develop and sustain a national economy, so too would a wholly voluntary approach to paying for the needed infrastructure be inadequate to develop a transmission grid capable of powering the world's largest economy. That alone is a reason to reject Commissioner Christie's dissenting views.

12. In addition, the dissent's approach would result in subpar transmission planning. Our nation needs transmission planning that looks ahead on the decades-long timeframe that is relevant to building backbone transmission facilities that will likely last a half-century or more. And transmission needs can best be predicted by considering many factors to discern their aggregate effect. Those include economics and technology fundamentals, changing demand patterns across customers of all types (including corporations), the full panoply of federal, Tribal, state, and local policy contributions, and even the changing weather patterns, which pose increasing challenges to maintaining a reliable and resilient electric grid. Rather than reflect that integrated reality, Commissioner Christie's approach asks planners to isolate select state public policies and focus on how each individually shapes the grid. That too is a recipe for down-sizing needed infrastructure in a way that will result in less efficient or cost-effective investments that fail to meet this critical moment.

## II. The Dissent Misrepresents the Final Rule

13. Commissioner Christie's dissent responds to a strawman of his own making, not the final rule. And, even so, the dissent's critique of the final rule ultimately boils down to one principal issue: the failure of the rule (in his view) to give every state an absolute right to veto the costs of a transmission facility, even one from which the state's consumers would derive economic and reliability benefits. Although we respect his perspective, we disagree that the changes he seeks are legal—much less legally required—or that a final rule premised on his vision would beget the energy infrastructure needed to maintain reliability and affordability. In any case, his statement mischaracterizes critical aspects of the final rule, the most fundamental of which we address below.

14. First and foremost, Commissioner Christie asserts that Long-Term Regional Transmission Facilities are public policy projects whose purpose is to facilitate state efforts to shape the resource mix. He is wrong. This final rule requires transmission providers to comprehensively consider the factors that will shape the transmission needs of tomorrow. Although state efforts to shape the resource mix are one of many factors transmission planners are required to consider under this final rule, Commissioner Christie's narrow focus on them misses the forest for a couple trees. The requirement to consider state public policies is part of the much broader requirement to comprehensively consider *all* significant factors shaping future transmission needs, where other factors, including the fundamental economic and reliability drivers, play a much bigger role. That Commissioner Christie is focused overwhelmingly on the state public policies with which he disagrees does not mean that the same is true of Long-Term Regional Transmission Facilities.

15. In any case, Commissioner Christie's proposal is arbitrary and capricious in its lack of any limiting principle. Transmission needs of all sorts—economic or reliability, near-term or long-term—are shaped by all manner of state public policy choices.

Fundamental state decisions, such as tax rates, zoning and land use laws, and almost every use of the police power more generally, inevitably shape the supply and demand of electricity. No transmission need is unaffected by those basic exercises of state power, which means that no transmission need can be fairly or accurately described as entirely divorced from the effects or consequences of state policy decisions.

16. While taking issue with some state policy choices, Commissioner Christie's vision contains no method for determining which state policies must be considered and which might escape scrutiny even though they too contribute to underlying transmission needs. Similarly, it contains no rubric for determining how to evaluate the cumulative effects of state public policies—such as taxation and land use laws—that are, in many cases, far in excess of those derived from the public policies on which he chooses to focus. Nor does it contain any explanation for subjecting Long-Term Regional Transmission Facilities to this suite of planning and cost allocation requirements, but not economic and reliability projects—which are, for the reasons noted above, inevitably at least in part the product of public policies. That sort of unexplained, arbitrary line drawing is exactly what the APA prohibits.[2]

17. Let us be clear: These are reliability and affordability projects. As the final rule explains, the minimum standards we establish provide that Long-Term Regional Transmission Facilities are to be identified and evaluated based on their reliability and economic benefits. To call them anything else—no matter how many times—is a misnomer, plain and simple.

18. Similarly, Commissioner Christie's claim that states will be forced to subsidize other states' public policy choices could not be further from the truth. A bedrock requirement of this final rule is that customers will only be required to pay for a share of a Long-Term Regional Transmission Facility to the extent they benefit from that facility. That is cost causation 101. While we provide transmission planners, in cooperation with their state regulators, ample flexibility to determine how to satisfy that bedrock requirement, any cost allocation methodology that causes customers to pay for projects from which they do not benefit—or to pay a cost share out of proportion to the benefits they draw from the project—would be patently unjust and unreasonable. That is black

[2] *See, e.g., Prometheus Radio Project v. F.C.C.*, 373 F.3d 372, 390 (3rd. Cir. 2004) (explaining that when an agency has engaged in line-drawing, "its decisions may not be 'patently unreasonable' or run counter to the evidence before the agency" (citations omitted)); *Sinclair Broadcast Grp., Inc. v. F.C.C.*, 284 F.3d 148, 162 (D.C. Cir. 2002) (explaining that lines drawn cannot be "patently unreasonable, having no relationship to the underlying regulatory problem" (citing *Cassell v. F.C.C.*, 154 F.3d 478, 485 (D.C. Cir. 1998)); *Am. Trucking Assocs., Inc. v. I.C.C.*, 697 F.2d 1146, 1151 (D.C. Cir. 1983) ("The arbitrariness which the [Administrative Procedure Act] proscribes is the failure to draw reasoned distinctions where reasoned distinctions are required.").

letter law under the FPA,[3] which we have expressly incorporated into the requirements of this final rule.[4]

19. The dissent is equally wrong to suggest that anything less than a unilateral right to veto cost responsibility for a regional transmission project is unfair to states. To the contrary, both courts and the Commission have long recognized that the just and reasonable standard of the FPA requires that customers pay for infrastructure they use and benefit from.[5] The dissent's approach, by contrast, would permit free ridership,

[3] *See City of Lincoln v. FERC*, 89 F.4th 926, 930 (D.C. Cir. 2024) ("The FPA's just and reasonable standard incorporates a cost-causation principle."); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) ("Under the [FPA], electric utilities must charge just and reasonable rates. For decades, the Commission and the courts have understood this requirement to incorporate a cost-causation principle—the rates charged for electricity should reflect the costs of providing it." (citations omitted)); *see also BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014) ("[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.").

[4] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Order No. 1920, 187 FERC ¶ 61,068, at P 1305 & n.2786 (2024).

[5] Beneficiary pays is founded on a recognition, grounded in the unbreakable laws of physics, that "the nature of power flows over an interconnected transmission system does not permit a public utility transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them." Order No. 1000, 136 FERC ¶ 61,051 at P 534; *see also id* P 535 ("the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them"); *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476-77 (7th Cir. 2009) (*ICC v. FERC I*) ("All approved rates must reflect to some degree the costs actually caused by the customer who must pay them . . . To the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." (internal citations omitted)); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("FERC and the courts have added flesh to these bare statutory bones, establishing what has become known in Commission parlance as the 'cost-causation' principle. Simply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *see, e.g.*, *Sw. Power Pool*, 182 FERC ¶ 61,141, at PP 12, 99-103 (2023).

allowing states to avoid paying by withholding their approval, while still receiving the substantial benefits of a more integrated, robust transmission system. Here too, both the Commission and the courts have expressly rejected that approach as inconsistent with cost causation.[6] Rather than ensure fairness, the dissent's approach would create perverse incentives, rewarding states that decline to pay for infrastructure development that demonstrably provides reliability and economic benefits to those states, while penalizing those who roll up their sleeves to get those projects built. That is a recipe for inaction, not for building the energy infrastructure we so badly need to maintain reliability and affordability.

20. We agree with Commissioner Christie that transmission development works best when states are key partners in the process. That is why we take the unprecedented steps described in the final rule to give them a central role. But partnership and collaboration are not the same thing as giving every state the right to veto cost responsibility for transmission projects thus allowing their residents to reap a windfall by benefitting from transmission facilities for which they did not pay their legally required share.

21. Commissioner Christie also asserts that the final rule deprives states of their long-standing authority. That is categorically false. Let us again be clear: States retain all the same authorities over retail rates and transmission siting they held prior to the final rule. Rather than deprive states of authority, the final rule *empowers* them with unprecedented opportunities to engage with transmission providers in developing a cost allocation framework.

22. Commissioner Christie's objection is to the structure of the FPA, and long-established, court-upheld Commission regulation of regional transmission planning under Order No. 1000, not the final rule. He objects to the transmission provider's role in deciding, without state approval, whether to invest in a transmission project and determine, subject to Commission oversight, which consumers must pay for it. But that basic structure is not new to the final rule—it is how transmission planning occurs today, consistent with the FPA and Commission precedent, including Order No. 1000. At Congress's direction, public utilities, not states, have the right to propose to the

[6] Order No. 890, 118 FERC ¶ 61,119 at P 561 ("there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it"); Order No. 1000, 136 FERC ¶ 61,051 at P 535 ("[if] the Commission could not address free rider problems associated with new transmission investment, [] it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory"); *El Paso Elec. Co. v. FERC*, 76 F.4th 352, 363 (5th Cir. 2023) ("No amount of emphasizing other competing interests permits FERC to sacrifice the foundational principle of cost-causation by refusing to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits." (citations omitted)).

Commission rates and practices affecting those rates and we cannot deprive them of those rights.[7] Neither states' siting authority nor their exclusive jurisdiction over retail rates give them the unilateral right to dictate matters subject to the Commission's exclusive jurisdiction, such as the transmission rates and practices affecting those rates that are the subject of this final rule.[8] For example, a state could reject siting or other approvals for the portion of a regional transmission project located within its jurisdiction, provided that its determination was consistent with relevant state and federal law. But states cannot stymie needed regional transmission projects by simply declining to pay for them. Nor is that concept new to this final rule. Under established economic and reliability planning, state policies are contributing factors to needed transmission, and states have never held a veto authority over costs for such facilities under Order No. 1000.[9] Nothing in this final rule changes those basic facts.

23. What has changed is that states now, *as a result of this final rule*, have an unprecedented opportunity to shape transmission planning and cost allocation, elevating our system of cooperative federalism with the states to a degree not previously seen in the history of this Commission. Most significantly, we are requiring transmission providers to host a dedicated forum for meaningful state participation in proposing cost allocation methods and processes. And the rule also permits a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Transmission Facilities. Beyond cost allocation, states will have an opportunity to provide input on how to account for specific factors in Long-Term Scenarios, and states can provide information on how their own policies and planning affect Long-Term Transmission Needs. The rule also requires transmission providers to consult with and seek the support of states regarding how Long-Term Regional Transmission Facilities are evaluated and selected. We expect that where states come together to articulate workable, legal frameworks for planning and paying for needed infrastructure, their transmission providers will listen.

24. Indeed, under the State Agreement Process provided in the final rule, states very well could agree to, and transmission planners could adopt, a version of Commissioner

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[7] 16 U.S.C. § 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) ("Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets.").

[8] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 253-83 (affirming Commission's legal authority to require participation in Long-Term Regional Transmission Planning).

[9] Indeed, Commissioner Christie recently approved, over the objection of other states, PJM's plan to regionally allocate the costs of transmission to address reliability concerns driven, at least in part, by Virginia's policy to incent siting of data centers in that state. *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,012 (2024).

Christie's preferred cost allocation approach.[10] So long as those expected to use the Long-Term Regional Transmission Facilities pay a share of the cost that is roughly commensurate with the benefits they will receive, nothing in this final rule prohibits states in a transmission planning region from adopting Commissioner Christie's preferred approach for funding the transmission facilities they need to ensure reliability and affordability.

25. Commissioner Christie also asserts that this final rule breaks with Order No. 1000 by mandating outcomes rather than regulating transmission planning processes. Here, too, he is wrong. The rule is clear that no transmission provider is required to select any particular project.[11] Instead, just as in Order No. 1000, the obligation on the transmission provider is to plan for the world as we expect it to be and then make its own business decisions after having conducted that planning process. The final rule's minimum planning standards do not un-do that core discretion. Requiring planning to be based upon documented drivers of transmission needs and to incorporate objective measures of how potential investments pay off improves the planning *process*, it does not mandate any particular outcome.[12] In short, in recasting the rule to fit his narrative, Commissioner Christie conveniently ignores one of its core elements: that it imposes no obligation to develop any regional transmission project.

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[10] We find Commissioner Christie's contention that the final rule would end PJM's use of its existing State Agreement Approach, and MISO and SPP's respective regional state committees, puzzling. Order No. 1920, 187 FERC ¶ 61,068 (2024) (Christie, Comm'r, dissenting, at P 11). The final rule enhances states' role and relaxes certain Order No. 1000 requirements for state-approved cost allocations. It is inexplicable that these additional flexibilities would result in transmission providers rolling back opportunities for state engagement in existing Order No. 1000 processes, where that is the opposite of the thrust of the final rule. Moreover, PJM's State Agreement Approach was approved outside of compliance with Order No. 1000 and has never served as PJM's exclusive *ex ante* cost allocation method, as Commissioner Christie suggests.

[11] Order No. 1920, 187 FERC ¶ 61,068 at P 1026 ("The Commission did not propose in the NOPR, and we will not require in this final rule, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.").

[12] *Id.* ("In other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.").

26. Finally, Commissioner Christie is also incorrect in arguing that this final rule violates the Major Questions Doctrine. He asserts two bases for that argument, neither of which hold water.

27. First, he contends that our *intention* in issuing this final rule is to elicit trillions in spending on transmission. As an initial matter, the goal of this final rule is to facilitate the development of transmission infrastructure *needed* to maintain reliability and affordability. That is the case no matter how many times or in how many ways Commissioner Christie purports to ascribe our 'true' intentions. In any case, his trillion-dollar estimates are nothing more than a sleight of hand that is unsupported by the record before us. To support his claim that this final rule will cause "literally trillions" in transmission investment, he cites to one academic study and one news article stating that in order to achieve a "net-zero" emissions level by 2050, trillions will need to be spent on transmission.[13] Putting aside whether that figure is accurate and whether "net zero" is an appropriate policy goal for the country—a question which we agree is not for this Commission to resolve—it is an astounding logical leap to say that because certain individuals believe a certain amount of investment is necessary to achieve a certain policy goal, that this rule will necessary cause customers to spend that amount of money. In any case, as the dissent points out, significant investments in transmission are already being made by public utilities around the country regardless of anything we do—or do not do—here today. This final rule regulates the process by which those investments are identified, evaluated and, where appropriate, selected in order to help ensure that they reflect the most efficient and cost-effective options available. That is what the Commission has been doing for decades; the fact that transmission has become a more politically salient topic does not transform our longstanding practice into a major question.

28. Second, he contends that our statement that the Commission has exclusive jurisdiction over the transmission planning practices that directly affect wholesale rates means that this Commission has crossed the major questions Rubicon. But it was the courts, not this Commission, that took that step. As he observes in his dissent, *South Carolina* concluded that the transmission planning practices regulated by Order No. 1000—which are the same practices addressed by this final rule—were practices that directly affected wholesale rates and thus fall squarely within the Commission's jurisdiction.[14] And as the courts have explained, where a practice meets that directly

[13] *Id.* (Christie, Comm'r, dissenting at P 3 & n.7.

[14] In *South Carolina*, it was undisputed that transmission planning generally was a practice that directly affected wholesale rates, but the court further held that the absence of regional transmission planning was itself such a practice. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 56-59 (D.C. Cir. 2014).

affecting standard, it falls within the Commission's exclusive jurisdiction.[15] This long-settled law in no way alters or dilutes the significant and critical role for states to play under their jurisdiction and, as noted above, we have significantly expanded that role in this final rule. Rather it means that the specific practices in the tariffs on file with this Commission, as required by this final rule, are within the Commission's exclusive jurisdiction, not that of the states. The final rule's recitation of black letter law hardly runs afoul of the major questions doctrine.

## III. We Encourage Transmission Providers to Facilitate Joint Ownership Structures

29. Finally, we would be remiss not to mention one policy priority that is not finalized in this rule: The creation of a federal right of first refusal for certain transmission facilities developed through a joint ownership structure. As the final rule explains, we find that proposal is better considered as part of our generic proceeding on Transmission Planning and Cost Management, where it can be evaluated alongside other proposals for ensuring that transmission facilities are developed as efficiently and cost-effectively as possible.[16]

30. Nevertheless, we underscore that our decision today should not be construed as a lack of support for the concept of joint ownership or the potential for a federal ROFR to effectively encourage its use. Indeed, joint ownership structures that partner transmission owners with other load-serving entities in their footprint, such as public power or non-profit cooperatives, can provide many benefits and should be encouraged.

31. In these arrangements, the load-serving entity partner's participation can reduce costs for customers in the footprint. Such joint ownership structures bring together diverse parties, allowing the participating entities to better allocate risks and responsibilities, capture efficiencies, and promote innovation, all to customers' ultimate benefit.[17] Moreover, by bringing a wider range of entities into the transmission

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[15] *See, e.g., Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 964 F.3d 1177, 1181 (D.C. Cir. 2020) ("Congress g[ave] the Federal Energy Regulatory Commission . . . exclusive authority over the regulation of the sale of electric energy at wholesale in interstate commerce, including both wholesale electricity rates and any rule or practice affecting such rates." (cleaned up)).

[16] Order No. 1920, 187 FERC ¶ 61,068 at PP 1563-64 & n.3346.

[17] *See, e.g.*, TAPS Initial Comments at 33-34 ("As explained in the TAPS 2021 White Paper, inclusive joint transmission ownership arrangements—whether structured as an inclusive transco, a shared system, or joint ownership of new transmission facilities—result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the

development fold, joint ownership can leverage additional sources of capital, including those that do not typically invest in transmission facilities, which can itself have significant benefits for customers.[18]

32. For example, TAPS highlights specific instances of joint ownership arrangements with tax-exempt public power entities providing significant savings to customers.[19] TAPS and APPA estimate these kinds of joint ownership arrangements can typically yield a "more than a 5% annual cost reduction in ratepayer-funded return and associated tax costs," which could produce billions of dollars in savings when applied to reasonable transmission investment forecasts.[20] Relatedly, NRECA highlights examples of joint ownership arrangements with electric cooperatives yielding reliability and efficiency benefits, including, among others, leveraging electric cooperative's ability to provide increased operations and maintenance support and access to lower cost financing through the Rural Utilities Service.[21]

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needs of all LSEs." (citing TAPS, *Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Site and Build Transmission Need to Support Our Changing Resource Mix* (June 2021), https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf)); *see also* Rob Gramlich et al., Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission*, at 11-30 (Feb. 2024) (attached to WIRES Supplemental Comments) (highlighting specific examples of large regional transmission projects that resulted from diverse partnerships, including with public power entities and cooperatives, and which met many transmission needs and produced a wide range of benefits).

[18] *See, e.g.*, APPA Initial Comments, attach. at 4-10 (Declaration of James Pardikes) (listing advantages in equity ratio, debt cost, and income tax expense, and opportunities for risk diversification as potential benefits of joint ownership arrangements with public power utilities); NRECA Reply Comments at 15-16; Citizens Energy Reply Comments at 2-4 (describing how its unique joint ownership business model enables Citizens to provide direct support to low-income ratepayers and disadvantaged communities, addresses multiple concerns that arise in transmission development, and advances multiple Commission policy goals).

[19] TAPS Initial Comments at 45 (examining savings across Vermont Transco, ATCLLC, Fargo Project, and SE Missouri Project).

[20] TAPS Initial Comments at 45-46 & nn.133-135; APPA Reply Comments at 4.

[21] GDS Assocs., *National Rural Electric Cooperative Association*, at 25-27 (Aug. 17, 2021) (attached to NRECA Initial Comments).

33. In light of those substantial benefits, we clarify that nothing in this final rule should be interpreted to prohibit or impair joint ownership arrangements. To the contrary, we encourage transmission providers, in compliance with this rule and elsewhere, to find ways to encourage these arrangements. For example, in compliance with this rule, transmission planners could use joint ownership as a factor to be considered in evaluating and selecting the more efficient or cost-effective solution to meet a long-term transmission need. Similarly, we note that the developers of a jointly owned transmission facility can consider seeking transmission incentives under section 205 of the FPA that reflect the risks and challenges associated with developing such facilities.[22] In addition, the Commission will continue to evaluate other potential actions to incentivize joint ownership, including considering in the Commission's cost management proceeding whether to provide a right of first refusal or other mechanisms to encourage its use.

* * *

34. Our electric transmission grid is at a crossroads. Our nation is facing down an extended period of unprecedented change in demand, supply, and the myriad other factors that fundamentally shape our energy needs. And we do so with a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality.

35. We have a choice: We can take consequential action to build the infrastructure needed to ensure reliability and affordability. Or we can pursue half-measures, which may help on the margins, but will ultimately leave us lacking the infrastructure we need to keep the lights on at a price that customers can afford. With this final rule, we emphatically choose the former path.

36. But we are not going down this road alone. As discussed above, we have opened the door for our state partners to play a leading role in shaping the next generation of energy infrastructure. We urge them to walk through it and deploy their unique

[22] *See Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129, at P 24 (2012) ("The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks."); *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC 61,057, at P 354 (2006) ("[T]o the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project. Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.").

perspectives as regulators and siting authorities of electric infrastructure to develop regionally tailored solutions. Together, we can forge a process that will serve customers for generations to come. This is the moment to step up, to develop both processes and physical infrastructure to withstand the changes and challenges ahead. This is the moment to build an electric transmission grid for the 21st century.

For these reasons, we respectfully concur.

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| _____ | _____ |
| Willie L. Phillips | Allison Clements |
| Chairman | Commissioner |

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation — Docket No. RM21-17-000

(Issued May 13, 2024)

CHRISTIE, Commissioner, *dissenting*:

## I. The Final Rule Is a Pretext for Enacting a Sweeping Policy Agenda Never Passed by Congress, Denies the States the Authority Promised by the NOPR, and Fails the Commission's Consumer Protection Duty under the Federal Power Act

1. The Federal Power Act (FPA) is, at its core, a consumer protection statute.[1] In FPA section 206, which today's final rule purports to be based on, Congress explicitly directed this Commission to protect consumers from public utility "rates" that are "unjust, unreasonable, unduly discriminatory or preferential."[2] This final rule, however,

[1] *E.g.*, *Towns of Alexandria, Minn. v. FPC*, 555 F.2d 1020, 1028 (D.C. Cir. 1977) (explaining that the FPA's "'primary aim is the protection of consumers from excessive rates and charges'") (quoting *Mun. Light Bds. v. FPC*, 450 F.2d 1341, 1348 (D.C. Cir. 1971)); *see also Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 492 (D.C. Cir. 1985) (recognizing that the benefits of rate predictability, which are the "whole purpose" of the filed rate doctrine, ought to be considered in light of the FPA's "primary purpose of protecting the utility's customers").

[2] 16 U.S.C. 824e. Under the FPA, the Commission is a regulator of wholesale public utility *rates*, not a national integrated resource planner (known in the lingo as an "IRP") of generation and/or transmission. *See, e.g.*, *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013) (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, at 62,080 (1995) ("[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable generation."). Further, FPA section 215, pertaining to electric reliability, explicitly leaves the construction of generation and transmission assets to state regulatory authority. 16 U.S.C. 824o(i)(2). Section 215 makes clear congressional intent to leave integrated resource planning to the states. Indeed, the overall statutory framework of the FPA—consistent with America's federal constitutional structure—makes it clear that *states* are the primary regulators of which

fails to fulfill the Commission's consumer protection duty required by the statute. The final rule should be seen for what it is: a pretext to enact, through administrative action, a sweeping legislative and policy agenda that Congress never passed.[3] The final rule claims statutory authority the Commission does not have to issue an absurdly complex bureaucratic blizzard of mandates and micromanagement[4] to be imposed on every transmission provider in the United States for the transparent goal of spending trillions of consumers' dollars on transmission *not* to serve consumers in accordance with the FPA, but instead to serve political, corporate, and other special-interest agendas that were never enacted into law.[5] The rates for transmission that will result from the final rule will not

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utility assets get planned and built, both generation and transmission, not FERC.

[3] *See, e.g.*, *W. Va. v. EPA*, 597 U.S. 697 (2022) (*West Virginia v. EPA*); *Dept. of Commerce v. N.Y.*, 139 S. Ct. 2551 (2019).

[4] In truly Kafkaesque fashion, the final rule is a doorstopper weighing in at just below 1300 pages, likely one of the longest, most complicated, and confusing orders the Commission has ever issued. Regulated entities—it applies to *all* public utility transmission providers in the United States, RTO and non-RTO—will need weeks just to read through it, much less decipher it, and then months of figuring out how to comply. Its very complexity raises the prospect of multiple rounds of compliance filings, no doubt punctuated by multiple deficiency letters, in order to push the transmission provider towards the outcomes the Commission wants to achieve. The final rule's very complexity renders it, if not arbitrary and capricious on its face, likely to be arbitrary and capricious in its enforcement.

[5] *See, e.g.*, Heather Richards, Zach Bright, Christian Robles, *3 energy issues to watch this spring at DOE, Interior and FERC*, Energywire, Mar. 18, 2024 ("FERC has promised a closely watched rule this spring on transmission that could be *key to President Joe Biden's ambitious aim to decarbonize the electricity grid by 2035*. . . . 'The sooner we get a final rule, the better. . . ,' said Caitlin Marquis [of] Advanced Energy United, a pro-clean-energy group. . . . [T]he Biden administration is in a race . . . until roughly midyear to finalize rules *before they are subject to the Congressional Review Act (CRA)* . . . . The Biden administration has said [today's final rule] will facilitate a build-out of interregional lines and grid interconnections needed to . . . *allow more wind and solar power to come online*. . . .") (emphases added) https://www.eenews.net/articles/3-energy-issues-to-watch-this-spring-at-doe-interior-and-ferc/; *see also* Peter Behr, *EPA power plant rule targets coal. Does that spell trouble for the grid?* Climatewire, May 3, 2024 ("But climate activists will not give up the 'zero by 2035' goal without a fight. President Biden made that steep commitment at a critical point in his 2020 candidacy to win the support of primary rival Sen. Bernie Sanders (I-Vt.) and his climate action activists. . . . [T]he hard road to a zero-carbon grid in 2035 is real *precisely because the Biden administration has pursued it*. . . . [Study authors] highlighted estimates that the

only be unjust, unreasonable, unduly discriminatory and preferential, but grossly unfair to tens of millions of American consumers already burdened with rapidly growing monthly power bills.

2. The fundamental principle historically embedded in utility regulation in the United States is to provide consumers with *reliable* power at the *least* cost under applicable law. This principle is fair and compelling because the vast majority of American utility consumers are captive customers who pay a monopoly utility for a vital public service—

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rate of high-voltage transmission line construction *must double to deliver the necessary new wind and solar energy*. . . . The [Biden] administration . . . is putting a strategy for big new lines in place. *FERC, with the support of Biden appointees, is preparing new policy to support big wires projects*. . . . 'You can't get around the fact that *you're going to need tens of thousands of miles of new transmission lines if you want to build the hundreds of gigawatts of wind and solar and batteries that many of us predict are needed to achieve decarbonization goals*,' said [former Obama energy secretary Ernest] Moniz.") (emphases added), https://www.eenews.net/articles/epa-power-plant-rule-targets-coal-does-that-spell-trouble-for-the-grid-2/; *see also* Zach Bright, *FERC sets date for landmark transmission rule*, Energywire, Apr. 19, 2024 ("FERC said it plans to hold a special May 13 meeting to consider its . . . transmission planning and cost-allocation proposal that's been a focus of *[lobbying] for expanding the grid to . . . move more renewable energy*. . . . *The Biden administration's goal of [net zero] by 2035 hinges on expanding the transmission system by two-thirds, the Energy Department said last year*.") (emphases added), https://www.eenews.net/articles/ferc-sets-date-for-landmark-transmission-rule/; *It's raining rules: Why the Biden administration is rushing to produce regulations*, The Economist, May 4, 2024, at 19 ("More regulations, big and small, are expected soon. *The Federal Energy Regulatory Commission is planning to rewrite the rules governing interstate electricity transmission, which is critical to President Joe Biden's decarbonisation plans*. . . . *Why the sudden spate? A previously obscure law, the [CRA], helps explain the rush.* It allows Congress, for a limited period, to pass resolutions of disapproval against finalised administrative regulations with which it disagrees. If both chambers of Congress pass such a resolution, and the president signs it, the rule is cancelled, short-circuiting the usual drawn-out process of litigation or a subsequent administration beginning a whole new rule-making effort. So once a regulation is properly created the clock starts ticking: the cancellation procedure is allowed for up to 60 days that the Senate is in session—including the last 60 days of an administration that loses a presidential election.") (emphasis added), https://www.economist.com/united-states/2024/05/02/why-the-biden-administration-is-rushing-to-produce-regulations; *see infra* nn.8, 10, 13, 15, 16, 67.

electrical power—which no one can live without in modern society. Transmission is an essential component of this vital public service,[6] so necessary transmission must be built.

3. Today's final rule, however, is not about providing reliable power to consumers at least cost through just and reasonable rates as required by the FPA, despite the final rule's claim. And it is certainly not about being fair. On the contrary, the final rule inflicts staggering costs on consumers by promoting the construction of trillions of dollars of transmission projects,[7] not to serve consumers in accordance with the FPA, but to serve a

[6] The transmission component of utility service has typically been provided by the incumbent monopoly utility at the load-serving local level, and local transmission planning and/or construction is generally subject to state-regulated IRP or permitting processes, especially in non-RTO regions. The final rule imposes numerous additional requirements for local transmission planning, including even micromanaging how local "stakeholder" meetings are supposed to be conducted, which may conflict with state IRP proceedings and represent yet another FERC encroachment into areas of traditional state authority. *See Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Order No. 1920, 187 FERC ¶ 61,068, at Section IX.B.3.a (2024) (Final Rule). It is highly doubtful that the micromanagement of stakeholder meetings in local planning would pass judicial review under *CAISO v. FERC*, in which FERC's attempted micromanagement of an ISO's governing board appointments was rejected as not sufficiently grounded in FERC's rate-setting authority under the FPA. *See Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 400 (D.C. Cir 2004) (*CAISO v. FERC*).

[7] The Princeton Net Zero study is often cited, but it is only one of many estimates of the trillions of dollars in additional costs to be imposed on consumers. Using the Princeton study, the cost estimates of the transmission buildout necessary to achieve "net zero" range across different scenarios, with one scenario calling for transmission capacity to *quintuple (5x)* between 2020 and 2050, which is predicted to cost *$3.56 trillion*. *See* Princeton University Net Zero America Final Report Summary, Slide 29, https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf. I would emphasize that the sticker price of a utility asset is only a fraction of the ultimate cost to consumers, because the "going in" price will increase by a multiple of many times the original cost over the life of the asset, because the cost of capital, both a profit to the utility (known as Return on Equity, or ROE) and the cost of debt, will be paid by consumers. So, if Princeton gives an estimate of $3.56 trillion for new utility assets needed to reach the "net zero" goal, the *actual* cost to consumers over the life of the assets will be many times more than that estimate. *See also* Diana DiGangi, *US won't reach net zero emissions without transmission buildout: DNV*, Utility Dive, Sept. 25, 2023 ("*$12 trillion* will be spent on clean energy in North America by 2050 . . . to meet . . . net zero emissions targets . . . . Some of the biggest barriers to net zero in the U.S. include the *lack of transmission buildout* . . . .) (emphases

major policy agenda never passed by Congress, to serve the profit-making interests of developers of politically preferred generation, primarily wind and solar, and to serve corporate "green energy" preferential purchasing policies.[8] As such, the final rule does not deserve a shred of deference under *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*[9] in any form. Today's final rule is much less the product of reasoned decision-making or the agency's specialized expertise, as of political pressure

added), https://www.utilitydive.com/news/net-zero-transition-clean-energy-north-america-transmission-buildout/694621/.

[8] *See, e.g.*, Peter Behr, *DOE unveils critical grid corridors for Biden climate goals*, Energywire, May 8, 2024 ("'*To meet our climate goals we have to more than double our transmission capacity*,' said top White House clean energy adviser John Podesta, who has led a Cabinet-level push to get long-delayed transmission projects under construction.") (emphasis added), https://www.eenews.net/articles/doe-unveils-critical-grid-corridors-for-biden-climate-goals/; Peter Behr, *More, More, More: Biden's clean grid hinges on power lines*, Energywire, May 23, 2022 (stating that "the Biden administration is seeking an *unprecedented expansion of high-voltage electric lines to open new paths to wind and solar energy.* 'We obviously need *more, more, more transmission to run on 100 percent clean energy. . . ,*' Energy Secretary Jennifer Granholm said in February.") (emphasis added), https://subscriber.politicopro.com/article/eenews/2022/05/23/more-more-more-bidens-clean-grid-hinges-on-power-lines-00030117; *see also supra* n.5 and *infra* nn.10, 13, 15, 16, 67.

[9] 467 U.S. 837 (1984) (*Chevron*).

and special interest lobbying.[10] In the chapter on "regulatory capture"[11] in future economics textbooks, today's final rule should be a featured case study.

4. The final rule orders *all* transmission providers, RTO and non-RTO, to plan costly regional transmission for some *allegedly predictable* generation mix 20 years in the future (a generation mix which, as a practical matter, is impossible to predict so far into the future).[12] The obviously pretextual agenda of the final rule, however, is not to *predict*

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[10] *See* Catherine Morehouse, *FERC to tackle "historic" transmission planning rule in May*, PoliticoPRO, Apr. 18, 2024 ("FERC has been *under enormous pressure from lawmakers, clean energy developers, environmentalists and others* to finalize the rule that Chair Willie Phillips has promised will be 'historic' and the 'greatest development regarding electric transmission rules in the country in over a generation.'") (emphases added), https://subscriber.politicopro.com/article/2024/04/ferc-to-tackle-massive-transmission-planning-rule-next-month-00153191; *see also, e.g.*, Sen. Charles E. Schumer July 24, 2023 Comments at 1-2 (urging the Commission to ensure that "any final rule *must . . . prescribe* a set of benefits" to be used in transmission planning and that "it will be necessary that either" [the transmission provider, or FERC *shall impose* cost allocation] "when any state withholds support on a cost allocation method" [which risks] "*states that benefit from a transmission line" [acting as] "free riders [to] avoid any costs*.") (emphases added); Sen. Martin Heinrich, et al. (consisting of 20 additional Senators) Jan. 19, 2024 Comments at 2 (urging the Commission that "the final rule *must require* consideration of a . . . specific set of transmission benefits for . . . *cost allocation* processes") (emphases added); Sen. Sheldon Whitehouse Nov. 7, 2023 Comments at 2 (stating that "FERC should include [a list of required benefits] in its final rule"). As explained extensively herein, mandating benefits is a device for imposing costs on consumers in states that never agreed to the selection criteria or cost allocation. The deeply granular nature of the instructions to the Commission in these letters is more evidence that this final rule is a pretext to use an administrative agency to enact legislation that Congress never passed. *See also supra* nn.5, 8 and *infra* nn.13, 15, 16, 67.

[11] Luigi Zingales, *Preventing Economists' Capture*, University of Chicago Booth School of Business Review, July 1, 2014 ("In simple words, regulatory capture exists when a regulatory agency, created to act in the public interest, ends up advancing interests of the industry it is charged with regulating."), https://www.chicagobooth.edu/review/preventing-economists-capture.

[12] The example of the Potomac-Appalachian Transmission Highline (PATH) fiasco is a strong warning about the folly of spending billions of consumers' dollars to build transmission based on predictions of a generation mix in 20 years. *Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring at P 3) (PATH Concurrence) ("[C]onsumers have paid roughly *$250 million* for a project that was never built nor found needed by a single state regulator.")

the generation mix 20 years forward, but to *produce* the *preferred* generation mix that the current presidential administration, some huge multinational corporations,[13] some members of Congress, and other special interests want *now*. In fact, the final rule is not even about planning *transmission,* but is about planning *policy*, and it is very preferential about the policies it wants to promote. As with the Great Oz,[14] pulling back the curtain exposes the final rule for what it really is: An essential component in a comprehensive plan by the current presidential administration to push what the media describe as "green policies" designed to prefer and promote the wind and solar generation it favors while simultaneously *forcing* the shutdown of the fossil fuel generation it disfavors,[15] both

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(emphasis in original), https://www.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12; *see also* PJM Initial Comments at 62 ("In short, the volatility of input parameters cancelled the need for a $1.8 billion transmission line identified in 2007, that was confirmed to be needed five years out in 2012, but by 2012 was no longer needed for at least another 15 years, if at all."). Rather than wind or solar—which the final rule implicitly presumes will be the predominant generating resource in 20 years—it is just as foreseeable that the predominant share of generation in the U.S. could be nuclear, an essential dispatchable resource, as small modular reactor technology matures and economies of scale produce lower costs, or it could be green hydrogen. It could even be fusion or some new technology currently either nascent or unknown. *No one knows today*. Building trillions of dollars of transmission on a *prediction* that intermittent wind and solar will be the predominant generating resource in 20 years is just a costly guess.

[13] *See, e.g.*, Clean Energy Buyers Jan. 22, 2024 Comments ("Many of our businesses cannot grow without more *clean generation* resources . . . . States may miss out on economic growth opportunities without . . . access to the *types of generation resources* needed to attract growing and innovative industries.") (emphases added). Among the signers of these comments were Amazon, Apple, eBay, Google, Green Impact Technologies, Meta, Microsoft, Nike, Rivian, Salesforce, Target, Walmart and several other multinational corporations. The FPA gives FERC no authority whatsoever to use the "green energy" purchasing preferences of privately owned, for-profit multinational corporations as the basis to impose a *mandatory* transmission planning and cost allocation rule that will cost consumers trillions of dollars. The FPA does not recognize such corporate preferences; indeed, the FPA *forbids* preferences. *See also supra* nn.5, 8, 10 and *infra* nn.15, 16, 67.

[14] *The Wizard of Oz* (Metro-Goldwyn-Mayer 1939).

[15] *See, e.g.*, Catherine Morehouse, *DOE launches effort to cut federal permitting for new power lines in half*, PoliticoPRO, Apr. 25, 2024 ("The [U.S. Dept. of Energy] program is the *latest move by the Biden administration to speed up the . . . process for new transmission lines deemed critical to carrying dispersed wind and solar*

needed to meet its political commitment. Let me emphasize: Whether the policies being promoted in this final rule can be described as "green, purple, red or blue" is irrelevant. The point is that FERC, as an *independent* agency, has no business promoting the policies of any one party or presidential administration, especially when, as here, the effort to do so goes far beyond FERC's legal authority and fails to perform our consumer protection function under the FPA.

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*resources . . . . It also comes on the heels of an announcement from the EPA to tighten emissions standards for fossil-fueled power plants* — a move that will necessitate bringing more low-carbon resources onto the power grid to meet growing demand *as [fossil fuel] resources are forced offline.* 'DOE's work complements *what our partners across the administration are doing* . . . to deliver cleaner power . . . ,' Energy Secretary Jennifer Granholm told reporters . . . .") (emphases added), https://subscriber.politicopro.com/article/2024/04/doe-launches-effort-to-cut-federal-permitting-for-new-power-lines-in-half-00154189; *see also* Catherine Morehouse, *Energy regulator's exit may flummox Biden's green plans*, Politico, Feb. 9, 2024 ("[FERC] is poised to lose its biggest climate advocate and potentially shut down one of the White House's *best avenues to push its green policies. . . .* That buildout is needed to accommodate . . . *wind and solar projects that are critical to meeting the Biden administration's climate and clean energy goals*.") (emphases added), https://subscriber.politicopro.com/article/2024/02/energy-regulators-exit-may-flummox-bidens-green-plans-00140774; Molly Christian, *US transmission "in desperate need of an upgrade," Vice President Harris says*, Megawatt Daily, Jan. 20, 2023 ("Achieving lofty US climate goals will *require* '*thousands of miles of new high-voltage transmission lines all across our country*,' US Vice President Kamala Harris said. . . . '*To create our clean energy future, we must construct thousands of miles of new high-voltage transmission lines all across our country*,' [Harris said].") (emphases added), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/012023-us-transmission-in-desperate-need-of-an-upgrade-vice-president-harris-says; Alex Guillén, Ben Lefebvre, Annie Snider, Kelsey Tamborrino, Catherine Morehouse, James Bikales, *Biden administration eyes spring to finalize key climate regulations*, PoliticoPro, Dec. 6, 2023 ("The Biden administration is planning to finalize several major energy and environmental regulations in the first half of 2024 . . . . *That timeframe would help cement many of President Joe Biden's policy priorities in the event he does not win reelection*. . . . One of the top [FERC] priorities . . . has been to finalize a rule on power line planning and cost allocation . . . . *that is considered critical to unlocking new wind and solar resources.*") (emphases added), https://subscriber.politicopro.com/article/2023/12/biden-administration-plots-busy-spring-finalizing-key-climate-regulations-00130496. *See also supra* nn.5, 8, 10, 13 and *infra* nn.16, 67.

5. Yet here's the legal rub with the final rule's pretextual agenda: *Congress never voted to amend the FPA* to *direct* or even *allow* FERC (which is supposed to be *independent*) to be what Energy Secretary Granholm describes as one of "our partners across the administration" in implementing this "green energy" transformation agenda.[16] Such a sweeping policy agenda, which involves the transfer of literally *trillions* of dollars of wealth from consumers to special interests, is the epitome of a major question of public policy under *West Virginia v. EPA*. The final rule clearly intends to socialize trillions of dollars of costs for the transmission necessary to pursue this transformational agenda, and unlike the NOPR,[17] the final rule removes the principle that the states must consent to how and whether these massive costs are imposed on their consumers. The final rule goes to great lengths to use "nothing to see here" rhetoric,[18] but looking behind the curtain at what is really going on makes it obvious that the final rule is pretextual and a blatant violation of the major questions doctrine.[19] In its transparent effort to plan and

[16] *See* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, The New York Times, Apr. 25, 2024 ("[Biden] Administration officials are increasingly worried that their plans to fight climate change could falter unless the nation can quickly add *vast amounts of grid capacity to handle more wind and solar power* . . . . But experts say a rapid, large-scale expansion *may ultimately depend on Congress*.") (emphases added), https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html. *See also supra* nn.5, 8, 10, 13, 15 and *infra* n.67.

[17] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Notice of Proposed Rulemaking, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028, at P 303 (2022) (NOPR).

[18] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at P 265 ("[W]hat matters is that this final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA.").

[19] *See infra* Section III.C. The final rule insists that it most assuredly does *not* implicate a major question of public policy, Final Rule, 187 FERC ¶ 61,068 at PP 275-279, much like Captain Renault in *Casablanca* is "shocked, *shocked* to find gambling going on in here" as he pockets his winnings. *Casablanca* (Warner Bros. Pictures 1942); *but see* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, "'I've called [the final] rule the *biggest energy policy in the country*.'") (emphasis added), https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html. *See* Catherine Morehouse, *FERC to tackle "historic" transmission planning rule in May*, PoliticoPRO, Apr. 18, 2024 (quoting Chairman Phillips describing the final rule as "*historic*" and the "*greatest development regarding electric transmission rules in the*

fund trillions of dollars' worth of transmission to facilitate a *preferred* generation mix predominantly of wind and solar, both for public policies as well as corporate purchasing preferences, it is also "preferential" and thus a clear violation of FPA section 206.

6. Put most simply, the final rule is a shell game that plays this way:

> *Step One:* For planning and cost allocation purposes, throw transmission projects that solve specific reliability problems or reduce congestion costs into the same bucket as projects designed to promote public policies or corporate "green energy" preferences and disguise the purpose of very different projects by re-labeling *all* projects in the new bucket with the innocuous-sounding name "Long-Term Regional Transmission Facilities."
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> *Step Two:* Mandate planning inputs that must be used in determining which projects get selected for regional plans, which starts the money flowing from consumers to developers before any state has even evaluated the need for, or cost of, the projects.
>
> *Step Three:* Mandate benefits that will ultimately affect the allocation of costs to consumers across a multi-state region. Combined with Steps One and Two, this makes consumers involuntary "beneficiaries" who will then be forced to pay for projects that promote another state's public policy or corporate "green power" commitments.
>
> *Step Four:* Order all transmission providers to develop and file a cost allocation formula that will automatically be the default applicable to the entire bucket of Long-Term Regional Transmission Facilities.
>
> *Step Five:* Remove the NOPR's requirement that states must consent to the details of Steps One through Four before their consumers can be burdened with costs.

7. Let's drill down on the details of the final rule's shell game. The final rule seeks to shift the costs of transmission projects whose purpose is to implement state or local public policies promoting wind and solar generation (commonly referred to as "public policy projects" or "policy-driven projects") and big corporation "green energy" preferences by putting those projects into the same regulatory bucket—both for planning *and* cost-allocation purposes—with fundamentally different types of projects, those designed either to solve identified *reliability* problems (an engineering purpose, not a political or corporate purpose) or to provide quantifiable congestion cost savings (*economic* projects).[20] The final rule labels *all* projects thrown into the new bucket as

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*country in over a generation. . . .*") (emphases added).

[20] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 1474 ("[T]ransmission providers

"Long-Term Regional Transmission Facilities."[21] Lumping policy-driven projects with the other very different types of projects is a sleight-of-hand move to disguise the costs of the policy-driven and corporate-driven projects that the final rule is promoting.[22] Put most simply, reliability projects are driven by engineering, economic projects by economics, public policy projects by politicians, and corporate "green energy" policies by management and investors looking to maximize their returns or satisfy investment goals not recognized by the FPA.

8. Then to further promote its preferred policy projects, the final rule mandates planning criteria to be used in the planning of Long-Term Regional Transmission Facilities,[23] including the "categories of factors" that must be used in developing long-

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may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types.").

[21] *Id*.; *see also id.* PP 41, 250-251. In terms of labeling, at least Order No. 1000 described public policy projects honestly, as those that address "transmission needs driven by Public Policy Requirements." *See, e.g.*, *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at PP 2, 6 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (*South Carolina*); *see also id.* PP 11, 47.

[22] *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,012 (2024) (Christie, Comm'r, concurring at P 6 n.12) ("I note too that in PJM's [Regional Transmission Expansion Plan (RTEP)] review it offers a good example of how components of two different types of projects, a specific reliability solution and [State Agreement Approach (SAA)] Project, can be combined into one project that meets both needs. PJM describes in its filing how it solved a Window 3 specific reliability problem by combining that solution with an SAA project into an Incremental Multi-Driver Project. . . . This is a good example of how a multi-driver project should work: The reliability need is specific and would require a specific reliability solution that would, on its own, merit inclusion in the RTEP as a reliability project, and the SAA project, which is a supplemental – not a reliability – project, if feasible as it is in this specific case, can be planned in a way to meet the specific reliability need. Costs are allocated by PJM proportionately to each component of the project, one percentage allocated as a reliability project under PJM's formula, the other percentage wholly allocated to New Jersey for the SAA project.") (internal citation omitted).

[23] Final Rule, 187 FERC ¶ 61,068 at Section III.

term planning scenarios[24] and the list of benefits that must be used by planners in cost-benefit analyses.[25] All of these mandatory features are transparently intended to "pre-cook" outcomes by manipulating the planning and evaluations that determine which projects are selected for regional transmission plans. (It is emblematic of the entire final rule that it did *not* include "saves retail customers money" as one of its mandatory benefits for evaluating projects.)[26] The shell game's purpose is to ensure that preferential policy and corporate-driven projects are selected for regional transmission plans, which conveniently ensures that such projects are eligible for cost recovery through FERC's very generous (to developers, not consumers) formula rate mechanism. As further proof of the nature of the shell game, the final rule does not require transmission providers to identify the benefits used (other than those mandated), or how those benefits were specifically calculated, for cost allocation purposes.[27] While the final rule insists that it is not mandating *outcomes*, when you manipulate the *inputs* of transmission planning, you are effectively mandating outputs.[28]

9. But that's not all; here comes the worst part of the shell game. The final rule then requires every transmission provider in America to file an *ex ante* cost allocation formula that is applicable to the whole bucket of projects,[29] which now includes public and corporate-driven policy projects, *in order to socialize the costs of these projects across the entire region, even when states in a region have never consented for their consumers to bear the costs of such projects*. The final rule seeks to justify this imposition of costs on non-consenting states by treating their consumers as "cost causers" or "beneficiaries,"[30] which is justified by—now circle back to earlier in the shell game—the

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[24] *Id.* P 409. Among the *mandatory* categories of factors that the final rule dictates must be used to drive long-term planning throughout the entire country are, *inter alia*: (i) *state and local laws affecting the resource mix*, (ii) state and local laws on *decarbonization*, (iii) generator interconnection requests and withdrawals (another way to subsidize and prefer wind and solar developers which dominate the queues), and (iv) *corporate*, state and local government commitments to *purchase "green" energy*. Let me emphasize: these planning factors are *mandatory* for transmission providers to use, exposing the final rule's pretextual agenda for what it really is.

[25] *Id.* PP 3, 269, 719-720.

[26] *See, e.g., id.* P 720.

[27] *Id.* PP 1505-1511.

[28] *Id.* P 965.

[29] *Id.* P 1291.

[30] *See, e.g., id.* P 1305 n.2786 ("The cost causation principle requires costs to be

final rule's imposition of mandatory factors and benefits that must be used in the evaluations of projects.[31] By lumping reliability and economic projects into the same planning bucket as public and corporate-driven policy projects, the final rule seeks to affix the tags of "cost causer" and "beneficiary" to *all* consumers in a multi-state region, to justify sticking them with costs even if their state officials never consented. So despite the final rule's disingenuous claims to the contrary,[32] the intent and effect of this shell game is to enable the costs of corporate and public policy-driven projects to be socialized across an entire multi-state region and thus shifted onto consumers in states that never agreed to bear such costs. The *explicit* promise of the NOPR, that states would have to *consent* for their consumers to bear such costs, has been broken in this final rule.

10. When I voted for the NOPR, I made it absolutely clear I was voting for it because it reflected a *compromise* in which public and corporate policy-driven projects could be

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allocated to those who *cause* the costs to be incurred and *reap the resulting benefits*.") (emphasis added). A true statement on its face, but utterly disingenuous here. By mandating its preferred factors to be used in long-term planning, by mandating certain benefits to be used in evaluating projects, and by denying transparency as to what other benefits are used to evaluate projects and *how* benefits are being calculated, which drives cost allocation, the final rule effectively will hide the specific costs of policy and corporate-driven projects and essential information as to how costs are being calculated and allocated across a multi-state region. *See also supra* n.10.

[31] These key elements of the shell game respond almost precisely to the lobbying demands of various interest groups. *See, e.g.*, Environmental Groups Dec. 8, 2023 Comments ("Transmission providers *must* perform long-term (at least 20-year), forward-looking assessments. . . . They *must* . . . [include] planning for *state clean energy laws and policies, [and] scenarios with high renewable penetration* . . . . Scenarios *must* evaluate all benefits that transmission projects would deliver and *use these assessed benefits as a basis for project selection.* . . . The Commission also should create a *default cost allocation* policy that meets this same standard . . . .") (emphases added). Among others, the signers of this letter include: Advanced Energy United, American Clean Power Association, Clean Air Task Force, Earthjustice, Environmental Defense Fund, Evergreen Action, League of Conservation Voters, National Wildlife Federation, Natural Resources Defense Council (NRDC), Sierra Club, Union of Concerned Scientists, and WE ACT for Environmental Justice. *See also supra* nn.8, 10.

[32] Final Rule, 187 FERC ¶ 61,068 at P 267 ("[N]othing in this final rule requires states to subsidize other states' public policies and, indeed, this final rule requires . . . that transmission customers within a transmission planning region need only pay costs that are 'roughly commensurate' with the benefits that *transmission providers estimate* they will receive from a transmission facility.") (emphasis added).

incorporated into long-term planning, but *only if* the states had the authority to consent *both* to planning criteria, including benefits used in cost-benefit analyses to evaluate projects and selection criteria, as well as to cost allocation.[33] In my concurrence to the NOPR I wrote:

> Even more importantly though, for these [long-term] projects, the NOPR proposes to *require* the regional planning entities to consult with and *seek the agreement of the relevant states to both the selection criteria for these projects and to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies.* The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects — such as, for example, the "highway-byway" formula approved by the SPP Regional State Committee — or states can agree to a process for a project-by-project agreement on cost allocation among one or several states — such as, for example, the State Agreement Approach in PJM — or states may choose some combination of both.[34]
>
> And let me emphasize . . . *no individual state's consumers can be forced to bear the costs of another state's policy-driven project or element of a project against its consent.*[35]
>
> The bottom line for me is this: I believe that elevating the role in planning and cost allocation of state regulators — *who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component* — will make it *more likely, not less,* that necessary transmission can get built *while ensuring that rates resulting from these types of policy-driven projects will not be*

[33] NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at PP 11-12, 14) (NOPR Concurrence); *see also id.* P 5.

[34] *Id.* P 11 (emphasis in original and added).

[35] *Id.* P 12 (emphasis added).

> *unjust and unreasonable, which they clearly have the potential to be*.[36]

The other members of the Commission, including the then-Chairman and both other members of today's Commission, also recognized the NOPR as a compromise.[37]

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[36] *Id.* P 14 (emphasis in original and added).

[37] From the Transcript of Apr. 21, 2022 Commission Open Meeting (April 2022 Open Meeting Tr.):

"CHAIRMAN GLICK: And I also want to finally thank my colleagues. I think this [NOPR] is a *really good product.* It is a product of a lot of discussion, *a lot of compromise*—which is what *the Commission is all about*—and I think *all of us can say we did not get everything in there, in the document, that we would like, but I think we all got enough in there and I think we achieved a significant and really remarkable level of consensus.* And I think that is very notable today." April 2022 Open Meeting Tr. 44:17-24 (emphases added).

"COMMISSIONER CLEMENTS: As the Chairman [stated] that reaching agreement on this proposal was not easy. I can say with confidence that *none of us voting for it would have written it this way if we were writing on our own. But I am proud that it is a bipartisan effort,* and I am thankful to my colleagues for proactively engaging and for thinking creatively to find alignment." *Id.* at 55:17-23 (emphasis added).

"COMMISSIONER CHRISTIE: But I think on balance the positive aspects of this [NOPR], *particularly for state regulators at the heart of planning and cost allocation for these types of projects,* changing [CWIP] to AFUDC[,] I think those are *positive, big steps forward for me on balance and it makes it worth voting for this [NOPR]*." *Id.* at 67:15-20 (emphasis added).

"COMMISSIONER PHILLIPS: I would first like to thank my colleagues for working collaboratively with me on this. . . . I don't think I have ever been a part of a process more collaborative than this process that we had in this NOPR." *Id.* at 67:24-25, 68:6-8.

To those who say that many elements of this final rule were also in the NOPR for which I voted, such as, for example, the mandatory categories of factors, I would respond: If I agree to get a root canal with anesthetic, but learn upon arrival at the dentist's office that I can still get the root canal but with no anesthetic, that is not the original deal.

11. Yet the many fundamental changes made in this final rule[38] subvert and violate that compromise. Of particular importance to my willingness—and that of many state regulator organizations—to support the compromise NOPR, was the explicit principle of state agreement to planning and selection criteria and cost allocation embodied in the NOPR. The final rule, however, *denies what the NOPR promised*: it denies state agreement to selection criteria,[39] it denies state agreement to the benefits to be used in evaluating projects for selection in regional plans and ultimate selection (which can start the money flowing from consumers to developers before a state siting or construction permit has even been issued),[40] and most importantly, it denies state agreement to cost allocation for public policy and corporate-driven projects.[41] The State Agreement Approach, used successfully in PJM for over a decade, is effectively terminated by the final rule. The final rule says that, *even if states in a planning region agree*, a "State Agreement Process" *cannot* be the sole chosen method for allocating costs of these projects; the transmission provider's own *ex ante* formula *must* be the default method, regardless of whether states have agreed to it.[42] In addition to a *de facto* termination of the PJM State Agreement Approach, the final rule could call into question mechanisms to facilitate the states' role in cost allocation that have been used in other RTOs and ISOs for years, including in SPP and MISO.[43]

12. And let's get real: Telling the states to negotiate for an alternative cost allocation when the transmission provider's *ex ante* formula has already been designated as the default is no real negotiation at all. The final rule points a regulatory gun at states' heads redolent of *The Godfather*:[44] "Here's an offer you can't refuse." And contrary to NARUC's eminently reasonable and practical request,[45] the final rule even requires only

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[38] *See infra* Section II.

[39] Final Rule, 187 FERC ¶ 61,068 at P 996.

[40] *Id.* PP 3, 269, 719-720, 903.

[41] *Id.* PP 1291-1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

[42] *Id.* To be clear, even if the states agreed on an alternative *ex ante* cost allocation method, or if they agreed on a cost allocation method under the State Agreement Process, the transmission provider could choose to file it but also *could ignore it. See infra* n.195.

[43] *See* Final Rule, 187 FERC ¶ 61,068 at PP 1291-1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

[44] *The Godfather* (Paramount 1972).

[45] Final Rule, 187 FERC ¶ 61,068 at P 1255 ("NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-

one Engagement Period for states to negotiate a different cost allocation from the transmission providers' *ex ante* cost allocation before that *ex ante* cost allocation becomes the default.[46] It is obvious that the final rule intends to lock in each transmission provider's own *ex ante* formula for many years to come and to deny states any avenue to challenge it even as times and circumstances change, no matter how high their consumers' power bills escalate due to rising transmission costs.

13. Essentially, the final rule replaces the NOPR's principle of requiring state agreement to selection criteria, benefits, and cost allocation with a charade of suggesting to transmission providers that they "consult with and seek support" from the states—while paradoxically "clarifying" that transmission providers do not actually need to obtain state consent—and the final rule uses other empty phrases such as allowing states to "inform" or "provide input on" the evaluation process and cost allocation.[47] But the final rule's real attitude towards the states and state regulators is embodied in this airily regal but perhaps unintentionally straightforward pronouncement: "[W]e do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive."[48]

14. The principle of cost allocation that was described in my concurrence to the NOPR—that states must consent to regional cost allocation of corporate and public policy-driven projects—reflects a core principle of American democracy: *fairness*. In this ratemaking context, fairness means that the people have the right to choose the policymakers who impose costs on them, so they can hold them accountable. This final rule is *unfair* because it gives FERC and the transmission providers it regulates the power to *impose* costs on consumers to pay for transmission driven by huge corporations and politicians in states other than theirs, and for whom they never voted. The final rule truly subverts the principle that the people, through their state's policymakers, must consent to bear the costs of another state's politicians and their policy choices, or the energy purchasing preferences of corporate managers and investors.

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Term Regional Facilities." (citing NARUC Initial Comments at 49-50)).

[46] *Id.* P 1368; *see also id.* P 1291.

[47] *See, e.g., id.* PP 268, 959, 994, 996-997, 1456.

[48] *Id.* P 1363 (citation omitted). A different attitude towards state regulators was apparent in the NOPR. *See* April 2022 Open Meeting Tr. 46:10-16 ("CHAIRMAN GLICK: [This] NOPR proposes to give the states a much more significant role in addressing cost allocation. I think it helps to have Commissioner Christie and Commissioner Phillips, two of our five Commissioners are former state regulators, and I think that really helps to have their background and their interest.").

15. And from the consumer standpoint, the timing of this rule could not be worse. American residential customers will pay about 16.23 cents per kWh next year, the *highest retail power cost for consumers in almost three decades*.[49] Unlike in years past, fuel costs are not the primary driver of these mounting prices to consumers; rather, transmission is. Transmission costs are rising rapidly, becoming an ever more burdensome part of consumers' power bills.[50] To cite just one major example, in PJM, the largest RTO by load in the country, the transmission component of wholesale power costs has essentially *tripled* over the past decade, from just $5.65/MWh in 2013 to $16.54/MWh last year. Transmission now constitutes almost a third of wholesale power costs, up from approximately 10% just a decade earlier.[51] In 2020, the PJM Market

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[49] *See* Robert Walton, *U.S. electricity prices outpace annual inflation*, Utility Dive, Mar. 13, 2024 ("U.S. electricity prices rose 3.6% over the last 12 months, outstripping the broader inflation rate of 3.2%, the Bureau of Labor Statistics reported Tuesday. And experts say *there is little chance for near-term consumer relief*. . . . And *federal policies aimed at electrifying end uses and reducing emissions could lead to even higher prices*, Travis Fisher, director of energy and environmental policy studies at the Cato Institute, told a House subcommittee Wednesday.") (emphasis added), https://www.utilitydive.com/news/us-electricity-prices-rise-customer-eia-outlook/710113/.

[50] *See, e.g.*, Zach Bright, *Electricity prices rise faster than inflation*, *EnergyWire*, Apr. 12, 2024 ("The Bureau of Labor Statistics found that electricity prices rose 5 percent over the past year. *That's higher than the overall consumer price index (3.5 percent) and any other single commodity, like food . . . and gasoline* . . . .") (emphases added), https://www.eenews.net/articles/electricity-prices-rise-faster-than-inflation/; *Electricity Inflation 30% Higher Than CPI Over Last 12 Months*" Electricity Transmission Competition Coalition, Apr. 10, 2024 ("Electricity inflation remains the highest consumer goods cost among the items in the Consumer Price Index according to the latest release of data by the Bureau of Labor Statistics. . . . The price of electricity has soared because of the *accelerating cost of transmission* . . . .") (emphasis added), https://electricitytransmissioncompetitioncoalition.org/electricity-inflation-30-higher-than-cpi-over-last-12-months/.

[51] State of the Market Report 2023, PJM Market Monitor, Vol. II, Section 1, at 18, Table 1-9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml; State of the Market Report 2014, PJM Market Monitor, Vol. II, Section 1, at 16, Table 1-9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec1.pdf; State of the Market Report 2013, PJM Market Monitor, Vol. II, Section 1, at 12, Table 1-9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-sec1.pdf; *see also* State of the Market Report 2019, PJM Market

Monitor reported that the cost of transmission exceeded the cost of capacity for the first time.[52] Nationally, transmission rate base nearly tripled in a decade,[53] and—assuming an 8.2% year-over-year growth rate, which occurred in 2022—is on track to double again in the next nine years, even without this rule's intent to spend trillions more on transmission. According to the U.S. Energy Information Administration, already one in three American households reports difficulty in paying their power bills.[54]

16. Don't fall for the absurd claim that this rule will somehow save consumers money through more holistic or efficient planning, a vacuous bureaucratic argument divorced from reality.[55] The sheer amount of new transmission costs that the final rule inflicts on consumers—and special interest groups want—is staggering, measured in the *trillions*,[56] not 'merely' hundreds of billions, of dollars.[57] And these staggering costs will not be

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Monitor, Vol. II, Section 1, at 18, Table 1-10, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec1.pdf.

[52] State of the Market Report 2020, PJM Market Monitor, Vol. I, at 17, Table 8, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf.

[53] *See* Jim O'Reilly, *Led by AEP and Duke, transmission growth poised to rebound from dip in 2022*, S&P Global Market Intelligence, Nov. 15, 2023 (showing bar graph providing that aggregate transmission rate base grew from $61.4 billion in 2012 to $163.1 billion in 2022), https://www.spglobal.com/marketintelligence/en/news-insights/research/led-by-aep-and-duke-transmission-growth-poised-to-rebound-from-dip-in-2022. Under this Commission's rate recovery protocols, the transmission owner gets to collect the annual costs of transmission depreciation from rate base, plus a profit, known as Return on Equity, or "ROE," often inflated by the many incentives the Commission typically approves, as well as operations and maintenance costs. As any utility regulator knows, "what goes into rate base comes out in customers' bills." So a rapidly rising rate base means rapidly growing consumers bills.

[54] Amanda Durish Cook & Tom Kleckner, *Overheard at 10th Annual GCPA MISO-SPP Forum*, RTO Insider, Mar. 12, 2024, https://www.rtoinsider.com/73311-overheard-10th-annual-gcpa-miso-spp-forum/.

[55] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at P 89.

[56] *See supra* n.7.

[57] Illinois Senator Everett Dirksen is said to have once quipped, "In Washington, a billion here, a billion there, and pretty soon you're talking about real money." The final

incurred to provide consumers with reliable power, but to serve political and corporate agendas. It is truly Orwellian newspeak[58] to claim that adding multiple trillions of dollars in transmission costs to consumer's bills will somehow "save" consumers money (even Orwell would be impressed at the sheer audacity of such a claim).

17. If FERC were seriously interested in saving consumers' money, it would be acting to rein in the wide array of transmission incentives regularly handed out to transmission developers that are direct transfers of wealth from consumers to developers (long known as "FERC candy"),[59] and acting to reform the automatic awarding of the presumption of prudence in formula rate proceedings. Literally *nothing* is being done about these forms of consumer exploitation in this final rule; instead, the final rule goes in the exact opposite direction.

18. To add further insult to consumers' injury, the final rule *walks back* the NOPR proposal that would have denied transmission developers the Construction Work in Progress (CWIP) incentive.[60] I have written many times that CWIP is simply unfair. CWIP is unfair because it makes consumers the unwilling "bank" for developers, but unlike a real bank, consumers don't get paid any interest and this Commission forces them to make involuntary loans.[61] Removing CWIP was strongly supported by those

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rule updates his quip to a "trillion here, a trillion there . . . ."

[58] George Orwell, *1984* (first published by Secker & Warburg 1949).

[59] *See, e.g.*, *Office of Ohio Consumers' Counsel v. Am. Elec. Power Serv. Corp.*, 181 FERC ¶ 61,214 (2022) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-addressing-rto-adders-related-e-2-ohio; *MISO*, 181 FERC ¶ 61,094 (2022) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-urging-action-re-rto-participation-adder-docket; Mary O'Driscoll, *FERC approves incentives for AEP, Allegheny grid projects*, Greenwire, July 21, 2006 ("The approvals came as the commission finalized rules intended to promote transmission-grid additions that outline specific rate and other incentives that FERC will consider for future construction projects — the *'FERC candy'* that critics contend gives the utilities incentives but not much in the way of corresponding requirements.") (emphasis added), https://subscriber.politicopro.com/article/eenews/2006/07/21/ferc-approves-incentives-for-aep-allegheny-grid-projects-234508.

[60] Final Rule, 187 FERC ¶ 61,068 at P 1547.

[61] *Baltimore Gas & Elec. Co.*, 187 FERC ¶ 61,030 (2024) (Christie, Comm'r, dissenting at P 7), https://www.ferc.gov/news-events/news/commissioner-christies-dissent-award-incentives-exelon-er24-1313; *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,200 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-

concerned with protecting consumers: by state regulators, by public power providers, and by state consumer advocates.

19. In my concurrence to the NOPR, I wrote:

> CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the

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events/news/e-7-commissioner-christies-concurrence-exelons-application-abandoned-plant; *The Potomac Edison Co.*, 185 FERC ¶ 61,083 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-potomac-edisons-abandoned-plant; *Montana-Dakota Utils. Co.*, 185 FERC ¶ 61,015 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-montana-dakota-utilities-co-regarding; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,136 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc-0; *GridLiance W. LLC*, 184 FERC ¶ 61,129 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-gridliance-west-regarding-transmission; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,034 (2023) (Christie, Comm'r, dissenting at P 8), https://www.ferc.gov/news-events/news/commissioner-christies-dissent-award-transmission-incentives-nipsco-er23-1904; *Otter Tail Power Co.*, 183 FERC ¶ 61,121 (2023) (Christie, Comm'r, concurring at P 8), https://www.ferc.gov/news-events/news/e-18-commissioner-christies-concurrence-otter-tail-power-company-regarding; *LS Power Grid Cal., LLC*, 182 FERC ¶ 61,201 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-ls-power-grid-regarding-transmission-incentives; *Nev. Power Co.*, 182 FERC ¶ 61,186 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nv-energy-regarding-transmission-incentives; *The Dayton Power and Light Co.*, 182 FERC ¶ 61,147 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-dayton-power-and-light-company-regarding; *Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,039 (2023) (Christie, Comm'r, concurring at P 3), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc; *NextEra Energy Transmission Sw., LLC*, 180 FERC ¶ 61,032 (2022) (Christie, Comm'r, concurring at P 3) (July 2022 Concurrence), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nextera-energy-transmission-southwest-llc; *NextEra Energy Transmission Sw., LLC*, 178 FERC ¶ 61,082 (2022) (Christie, Comm'r, concurring at P 3) (February 2022 Concurrence), https://www.ferc.gov/news-events/news/commissioner-mark-c-christie-concurrence-nextera-energy-transmission-southwest-llc.

> developer. CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer. . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does. *This NOPR proposal represents a major step forward in consumer protection and is a big reason I am voting for it.*[62]

By walking back the proposed CWIP denial, the final rule results in a *major step backwards* for consumers.[63]

20. In yet another major slap at consumers, the final rule seeks to shift the substantial costs caused by generation developers' interconnection requests from developers to consumers.[64] It does this by ordering transmission providers to revise their regional transmission planning processes to evaluate for selection regional transmission facilities that address identified interconnection-related transmission needs, and the final rule specifies that if such a facility is selected, *its costs will be regionally allocated*.[65] It also does this by ordering transmission providers to incorporate generator interconnection

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[62] NOPR Concurrence at P 15.

[63] By doing nothing about the consumer-paid "FERC candy" incentives that this Commission regularly hands out to developers, and even removing the provisions dialing back the CWIP incentive—and with its overall aim to pile trillions of dollars of additional costs for big corporate and politically-driven transmission on consumers, which will largely flow to the increased profits of wind, solar and transmission developers—the final rule could be the inspiration for one of the great country and western songs "Lord Have Mercy on the Working Man." Warner Bros. Nashville 1992 ("Why's the rich man busy dancing while the poor man pays the band? Oh they're billing me for killing me, Lord have mercy on the working man!").

[64] Final Rule, 187 FERC ¶ 61,068 at PP 472, 1106-1107, 1126, 1145.

[65] *Id*. PP 125, 1106-1107, 1126, 1145. Under "participant funding" mechanisms the generation developer pays the costs of the network upgrades costs it causes and consumers do not pay, which is only fair. The Commission's Order No. 2023 did not violate this principle. *See generally Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199 (2024). This final rule clearly intends to undermine this principle by moving interconnection costs into regional transmission planning and cost allocation, so consumers get stuck with the costs of interconnection, even though it is developers who profit from interconnection.

requests and withdrawals in their long-term transmission planning.[66] These are only schemes to shift interconnection costs from developers to consumers and will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential. Similarly, the final rule also inappropriately shifts preferential corporate-driven project costs onto *all* other consumers, who may disagree with, or even compete against, the corporate customers imposing their preferences. These provisions alone render the final rule's replacement rate unlawful under FPA section 206.

21. This Commission is, by statute, supposed to be *independent* of any presidential administration, but it has failed to defend that independence in this final rule, which is a naked pretext to enact the current administration's "net zero 2035" policy agenda, as well as to serve corporate agendas, and those of other profit-seeking special interests.[67] In failing to act independently,[68] this Commission has broken faith with state regulators and, even more importantly, broken faith with tens of millions of American consumers, who could be forced to bear literally trillions of dollars in costs for transmission lines to serve political, corporate and other special-interest agendas. This will not produce just and reasonable rates and is grossly unfair. This final rule is a dereliction of the Commission's duty under the FPA to protect consumers and far exceeds its authority under that statute.

## II. The Final Rule Is Fundamentally Different from the NOPR

22. The very essence of due process is notice and opportunity to be heard. Given the large number of fundamental changes to the NOPR, the final rule should be viewed as effectively a second NOPR and clearly should have been put out for additional public

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[66] Final Rule, 187 FERC ¶ 61,068 at P 472.

[67] *See* Miranda Willson, Heather Richards, Brian Dabbs, *Biden regulatory plan set to shake up energy sector*, Energywire, Dec. 7, 2023 ("The White House released a regulatory plan Wednesday that could shape President Joe Biden's energy legacy . . . . *[T]wo of the Federal Energy Regulatory Commission's most high-profile proposed transmission rules are listed on the [White House] agenda* . . . . One of those FERC rules would *change how large electric power lines are planned and paid for* . . . .") (emphases added), https://www.eenews.net/articles/biden-regulatory-plan-set-to-shake-up-energy-sector/; *see also supra* nn.5, 8, 10, 13, 15, 16.

[68] In the very recent past, this Commission stood up for its independence despite intense pressure from a presidential administration. *See, e.g.*, Steven Mufson, *Trump-appointed regulators reject plan to rescue coal and nuclear plants*, The Washington Post, Jan. 8, 2018 (explaining that "[t]he independent five-member commission [that rejected the president's proposal] includes four people appointed by President Trump"), https://www.washingtonpost.com/news/energy-environment/wp/2018/01/08/trump-appointed-regulators-reject-plan-to-rescue-coal-and-nuclear-plants/.

comment on the many fundamental changes. Because it was not, deliberately so, this final rule invites a court to remand with instructions for the Commission to give the public an opportunity to comment on the many fundamental changes from the NOPR.

23. The final rule issuing today is not the NOPR for which I voted. This pretextual final rule is fundamentally different in numerous ways, yet these fundamental changes were never put out for additional public comment.[69] These fundamental changes include, but are not limited to, the following:

24. *The Final Rule Imposes Preferential Policy and Corporate-Driven Project Costs on Consumers in Non-Consenting States*: Contrary to the NOPR, the final rule requires the filing of one or more *ex ante* cost allocation methods to apply to selected Long-Term Regional Transmission Facilities, setting up a mechanism to impose a regional cost allocation for preferential policy and corporate-driven projects when states do not consent, either by approving a cost allocation proposed by transmission owners, by RTOs, or one directly imposed by the Commission itself.[70] This is a fundamental change from the NOPR.

25. *The Final Rule Mandates Planning Criteria and Purported Benefits*: Contrary to the NOPR, the final rule mandates a specific set of planning criteria, and specifically purported benefits, that must be used by transmission providers for these preferential policy and corporate-driven projects.[71] Mandating the planning criteria and benefits is simply a way of "pre-cooking" outcomes and is directly contrary to the NOPR's explicit language that said it was *not* mandating outcomes, only a planning process.[72] This is a fundamental change from the NOPR.

26. *The Final Rule Abandons Regional Cost Allocation Principle (6)*: Contrary to the NOPR,[73] the final rule abandons the regional cost allocation principle[74] that would allow

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[69] The process leading to the adoption of Order No. 1000, the final rule's direct predecessor but one not nearly as sweeping in its application, was described in paragraphs 22 through 24 of that order. Order No. 1000, 136 FERC ¶ 61,051 at PP 22-24.

[70] Final Rule, 187 FERC ¶ 61,068 at PP 1291-1292.

[71] *Id.* PP 3, 269, 719-720.

[72] *See* NOPR, 179 FERC ¶ 61,028 at PP 9, 245.

[73] *See id.* P 302.

[74] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 685.

a transmission planning region to use different cost allocation methods for different types of facilities in a regional transmission plan. The final rule replaces this flexibility with a one-size-fits-all model.[75] This is a fundamental change from the NOPR.

27. *The Final Rule Effectively Eliminates a Voluntary State Agreement Process*: Contrary to the NOPR, the final rule effectively eliminates the use of a voluntary State Agreement Process, such as the one that has been used by PJM since Order No. 1000.[76] Not only is this directly contrary to comments filed by state regulators,[77] but it represents a fundamental change from the NOPR.

28. *The Final Rule Leaves the CWIP Incentive Intact*: Contrary to the NOPR, the final rule walks back the proposal not to allow use of the CWIP incentive.[78] This NOPR provision was one of the strongest consumer protection features.[79] Instead, the Commission leaves the CWIP incentive intact and that consumer protection has been removed. This is a fundamental change from the NOPR.

29. *The Final Rule Makes Local Transmission Planning Less Transparent*: Contrary to the NOPR,[80] the final rule makes fundamental changes to the NOPR's section on Local Transmission Planning.[81] Local Transmission Planning disclosure and transparency requirements no longer apply to asset management projects. This is a fundamental change from the NOPR.

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[75] Final Rule, 187 FERC ¶ 61,068 at P 1469 ("[U]nlike under Order No. 1000, transmission providers *cannot* adopt different Long-Term Regional Transmission Cost [A]llocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.") (emphasis added); *see also id.* P 1474.

[76] *See, e.g., id.* PP 1291-1292. A more detailed discussion on how the final rule effectively guts the State Agreement Process is in *infra* Section IV.B.1.b.

[77] *See* Final Rule, 187 FERC ¶ 61,068 at P 1323 (citations omitted).

[78] *Id.* P 1547.

[79] *See* NOPR, 179 FERC ¶ 61,028 at P 333; NOPR Concurrence at P 15.

[80] *See* NOPR, 179 FERC ¶ 61,028 at PP 400-413.

[81] Final Rule, 187 FERC ¶ 61,068 at P 1625.

## *III.* The Final Rule Exceeds FERC's Authority under the FPA

30. The final rule's determination that its reforms are within the Commission's legal authority under section 206 is flat wrong.[82] The final rule is just a pretext for enacting the current presidential administration's "net zero 2035" policy agenda, as well as that of large corporate buyers of preferential power and other special interests.[83] As such, the final rule goes far beyond the scope of Order No. 1000, as affirmed by *South Carolina*,[84] and exceeds FERC's authority under the FPA. Specifically, the final rule requires transmission providers to incorporate into their transmission planning seven categories of factors and a set of seven required benefits to drive the construction of projects to achieve the final rule's preferred substantive outcomes: namely, the development and purchase of certain preferred generation resources. In so doing, the final rule seeks to recast FERC as a national IRP planner with extraordinary powers to oversee and dictate to all public utility transmission providers in the country, in RTO and non-RTO regions, detailed instructions on planning transmission that fulfills the current administration's preferred policies as to the types of generation it wants to build, and to charge consumers trillions of dollars for this transmission. This transformation of FERC into a national IRP planner violates FPA section 201 by infringing on the authority of the states, and it reflects a tremendous expansion of the agency's power not permitted under the major questions doctrine.

### A. *South Carolina* Does Not Provide a Legal Justification for the Commission's Actions in the Final Rule

31. In arguing that the Commission is acting within its legal authority under section 206 to adopt its reforms for Long-Term Regional Transmission Planning, today's final rule heavily relies on *South Carolina*.[85] However, given the significant differences between Order No. 1000 and the final rule, that reliance is grossly misplaced.

32. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the Commission's *pro forma* open access transmission tariff could support the development of more efficient or cost-effective

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[82] *See id.* PP 86, 253.

[83] *See supra* Section I.

[84] 762 F.3d 41.

[85] *E.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 86, 253, 256 & n.604, 257 & n.605, 277.

transmission facilities.[86] Such reforms included, *inter alia*, the requirement for transmission providers to participate in regional planning processes; the requirement that such regional transmission planning processes must consider transmission needs that are driven by public policy requirements; and the requirement that transmission providers develop a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, with such method having to satisfy six regional cost allocation principles.

33. But Order No. 1000 was built on what may be a foundation of sand known as "*Chevron* deference." As the D.C. Circuit explained in *South Carolina*, "[t]he court reviews challenges to the Commission's interpretation of the FPA under the familiar two-step framework of [*Chevron*]."[87] The D.C. Circuit further explained that, "[i]f the court determines 'Congress has directly spoken to the precise question at issue,' and 'the intent of Congress is clear, that is the end of the matter.'"[88] This is often referred to as "*Chevron* step one."[89] The court stated, in contrast, that "[i]f . . . 'the statute is silent or ambiguous with respect to the specific issue,' then the court must determine 'whether the agency's answer is based on a permissible construction of the statute.'"[90] This is often referred to as "*Chevron* step two."[91] The D.C. Circuit explained that "*Chevron* step two . . . requires [the court] to uphold an agency's reasonable interpretation of a statute it administers."[92] That is, the court applies *Chevron* deference.[93]

34. In *South Carolina*, the D.C. Circuit applied *Chevron* deference to the Commission's interpretation of FPA section 206 in affirming many aspects of Order No.

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[86] *Id.* P 16 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3).

[87] *South Carolina*, 762 F.3d at 54 (citing *Chevron*, 467 U.S. 837).

[88] *Id.* (quoting *Chevron*, 467 U.S. at 842).

[89] *See, e.g.*, *id.* at 84.

[90] *Id.* at 54 (quoting *Chevron*, 467 U.S. at 843).

[91] *See, e.g.*, *id.* at 58-59 (citing *Chevron*, 467 U.S. at 843), 84.

[92] *Id.* at 76 (citing *Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 982 (2005)).

[93] Note, however, that the U.S. Supreme Court is revisiting the 40-year-old doctrine and has indicated that it may narrow or overturn it in the pending cases, *Loper Bright Enterprises v. Raimondo*, No. 22-451 (argued Jan. 17, 2024) and *Relentless v. Dep't of Commerce*, No. 22-1219 (argued Jan. 17, 2024).

1000, including its planning mandates.[94] In affirming the planning mandates, the court emphasized that Order No. 1000 focused on process and *not* substantive outcomes:

> In Order No. 1000, the Commission expressly "decline[d] to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan." More generally, the Commission disavowed that it was purporting to "determine what needs to be built, where it needs to be built, and who needs to build it." As the Commission explained on rehearing, "*Order No. 1000's transmission planning reforms are concerned with process" and "are not intended to dictate substantive outcomes.*" *The substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities remain within the discretion of the decision-makers in each planning region.*[95]

35. Similarly, in determining that Order No. 1000's public policy mandate fell within the Commission's authority under section 206, the D.C. Circuit noted the mandate did not promote any particular public policy:

> [Petitioners] seem to argue that the Commission can only exercise authority to promote goals specified in the FPA and that the public policy mandate cannot be justified with respect to any of those goals. This argument misunderstands the nature of the mandate. *It does not promote any particular public policy* or even the public welfare generally. The mandate simply recognizes that state and federal policies might affect the transmission market and directs transmission providers to consider that impact in their planning decisions. . . . This fits comfortably within the Commission's authority under Section 206. . . . [T]he public policy mandate bears directly on the provision of transmission service.[96]

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[94] *See South Carolina*, 762 F.3d at 56-59 (internal citations omitted).

[95] *Id.* at 57-58 (emphasis added; internal citations omitted).

[96] *Id.* at 89-90 (citation omitted).

Just as with Order No. 1000's planning mandates, the court again emphasized Order No. 1000's public policy mandate required the establishment of processes:

> But petitioners' attack is once again based on a misunderstanding of the orders. The orders merely require regions to establish *processes* for identifying and evaluating public policies that might affect transmission needs. The regions are free to choose their own manner of determining how best to identify and accommodate these policies.[97]

36. Finally, in affirming Order No. 1000's requirements pertaining to cost allocation, the court again applied *Chevron* deference to its interpretation of section 206.[98] The court noted that Order No. 1000 used a "light touch" in its cost allocation reforms:

> In keeping with the overall approach of the transmission planning reforms, [Order No. 1000] uses a light touch: it does not dictate how costs are to be allocated. Rather, [Order No. 1000] provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes.[99]

37. While Order No. 1000 used a "light touch," this pretextual final rule is heavy handed. To ensure that policy and corporate-driven projects are ultimately built so that the preferred generation is built, the final rule seeks to promote particular public policies and to dictate substantive outcomes through its reforms to the Commission's transmission planning and cost allocation processes.[100] If Order No. 1000 was upheld precisely because it was only mandating *processes*, not *outcomes*, then this final rule cannot stand on *South Carolina* because it nakedly intends to produce very specific outcomes.

38. How does it intend to do this? First, in contrast to Order No. 1000, which mandated consideration of public policies in transmission planning but *not* a particular policy,[101] the final rule *requires* transmission providers in their Long-Term Regional

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[97] *Id.* at 91 (emphasis in original; internal citations omitted).

[98] *Id.* at 84-86.

[99] *Id.* at 81.

[100] In so doing, the final rule violates section 201 as well. *See infra* Section III.B.

[101] *See South Carolina*, 762 F.3d at 89-90.

Transmission Planning to incorporate seven categories of factors—*i.e.*, specific policies, as I have emphasized. Most of these mandatory categories of factors, which drive long-term transmission planning, specifically relate to the development and purchase of "green energy," including, *inter alia*: (i) *state and local laws affecting the resource mix*, (ii) state and local laws on *decarbonization*, (iii) generator interconnection requests and withdrawals,[102] and (iv) *corporate*, state and local government commitments to *purchase "green energy."*

39. The final rule describes the relationship between the categories of factors, transmission needs, and benefits, among other terms:

> For purposes of this final rule, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.
>
> For purposes of this final rule, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning, which, as discussed in this final rule, includes running scenarios and *considering the enumerated categories of factors*.[103]

Thus, categories of factors clearly shape the identification of transmission needs. Demonstrating this causal relationship, the final rule explains that "best available data inputs are data inputs that . . . reflect the *list of factors* that transmission providers account for in their Long-Term Scenarios,"[104] and, in turn, "Long-Term Scenarios . . . incorporate various assumptions using best available data inputs about the future electric

[102] This factor category is another way to subsidize and prefer wind and solar developers, which dominate the interconnection queues.

[103] Final Rule, 187 FERC ¶ 61,068 at PP 38-39 (emphasis added).

[104] *Id.* PP 42, 633 (emphasis added).

power system . . . *to identify Long-Term Transmission Needs* and enable the identification and evaluation of transmission facilities to meet such transmission needs."[105]

40. And, as we know, the identification of needs leads to the identification of transmission facilities that meet such needs; the identification of transmission facilities in turn leads to the measure of the benefits associated with those facilities; and the measure of benefits informs the evaluation of those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation. Thus, as the categories of factors are slanted toward transmission to facilitate preferred generation, the resulting output of the transmission planning process will inevitably have a similar bent. In other words, the final rule's mandate of the categories of factors starts the domino effect toward the final rule's agenda, an agenda that goes far beyond Order No. 1000.

41. Second, in contrast to Order No. 1000, whose reforms "[were] concerned with process" and "[were] not intended to dictate substantive outcomes,"[106] the final rule requires transmission providers to measure a set of seven required benefits in their long-term transmission planning so that the pretextual agenda will be realized. By mandating minimum benefits that the transmission providers must use to evaluate potential transmission facilities,[107] the final rule is doing the opposite of using a "light touch;" rather, the final rule is putting its thumb on the scale, seeking to dictate outcomes of the transmission planning process. As I must continue to emphasize, by mandating benefits, the final rule makes consumers into involuntary "beneficiaries," who, through regional cost allocation, will be forced to pay for transmission projects that support the development and purchase of preferential power. Accordingly, as with the final rule's mandated categories of factors, the mandatory minimum benefits serve to advance the final rule's specific policy objectives regarding the resource mix. Such favoritism is blatantly unduly discriminatory and preferential in contravention of section 206, and therefore, the final rule is, simply put, not entitled to *Chevron* deference in any form.

### B. The Final Rule Violates FPA Section 201

42. The final rule also infringes on the states' authority over electric generation reserved to them by FPA section 201 and is thus *ultra vires*.

43. As relevant here, FPA section 201(b) provides:

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[105] *Id.* PP 40 and 302 (emphasis added).

[106] *See South Carolina*, 762 F.3d at 58 (internal citation omitted).

[107] Final Rule, 187 FERC ¶ 61,068 at P 965.

> The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[108]

Further, section 201(a) also specifies that "such Federal regulation . . . extend[s] only to those matters which are not subject to regulation by the States." Courts have found that "states have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable generation."[109] These powers are reserved to the states under section 201.

44. In *South Carolina*, the D.C. Circuit rejected the argument that section 201 prohibited Order No. 1000's transmission planning mandate.[110] The D.C. Circuit emphasized that "because the planning mandate relates wholly to electricity transmission, *as opposed to electricity sales*, it involves a subject matter over which the Commission has relatively broader authority."[111] The court also reasoned that "because [Order No. 1000's] planning mandate is directed at ensuring the proper functioning of the interconnected grid spanning state lines, . . . the mandate fits comfortably within Section 201(b)'s grant of jurisdiction over 'the transmission of electric energy in interstate commerce.'"[112] The court thus concluded that "Section 201 [did] not preclude the Commission's regulation of transmission planning in [Order No. 1000]" and that Order No. 1000 "[did] not interfere with the traditional state authority that is preserved by Section 201."[113]

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[108] 16 U.S.C. 824(b)(1) (emphases added).

[109] *See, e.g.*, *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d at 417 (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.*, 71 FERC at 62,080).

[110] 762 F.3d at 62-64.

[111] *Id.* at 63 (emphasis added) (footnote omitted)

[112] *Id.* (internal citations omitted).

[113] *Id.* at 64.

45. However, in contrast to Order No. 1000, the final rule absolutely does "interfere with the traditional state authority that is preserved by Section 201" to ensure that its preferential policy and corporate-driven projects get built. By mandating, *inter alia*, categories of factors that drive the transmission planning process and by mandating minimum benefits to be used in the evaluation of potential Long-Term Regional Transmission Facilities, the final rule seeks to spur the building of transmission so as to promote a specific policy objective: the development and purchase of preferential generation. Accordingly, although the final rule strenuously insists that it is not mandating *outcomes*,[114] it is doing so by manipulating the *inputs* of transmission planning (*i.e.*, "pre-cooking").[115] In other words, the final rule seeks to do indirectly what it may not do directly.

46. As I explained in my concurrence to the NOPR:

> States can prefer, mandate or subsidize specific types of generation resources, but the Commission cannot use its authority over transmission to pressure, steer or require regional planning entities to act as the Commission's agents and do indirectly what the Commission cannot do directly. The Commission is not a national integrated resource planner. Order No. 1000, to its credit, recognized this clear delineation between federal and state authority.[116]

I also explained that "the Commission cannot *impose* a preference for certain types of generation *nor require* regional entities to plan transmission designed to prefer or facilitate one type of generation over another."[117]

47. The text of the FPA gives this Commission *no* authority whatsoever to act as a national IRP planner for the purpose of promoting its preferred generation resource mix. Pulling back the curtain, that is exactly what this pretextual final rule seeks to do. By extending FERC's control over every public utility transmission planner in the country,

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[114] *See* Final Rule, 187 FERC ¶ 61,068 at PP 954-955, 1026-1028.

[115] *Id.* P 965.

[116] NOPR Concurrence at P 2; *see also id.* n.4 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 154 ("*[T]he regional transmission planning process is not the vehicle by which integrated resource planning is conducted*; that may be a separate obligation imposed on many public utility transmission providers and *under the purview of the states*.") (emphases added in NOPR Concurrence)).

[117] *Id.* P 12 (emphases in original).

RTO or non-RTO, and ordering them to plan transmission lines intended to advance preferred policy and corporate goals, the Commission is stepping into the role of national IRP planner. FERC's authority under the FPA is limited to matters that *directly* affect *rates*, not practices that may theoretically have some tangential, indirect effect on rates,[118] especially improper purposes such as ordering transmission planning to promote one or more states' public policies or corporate goals as to preferred generation resources. Congress intended FERC to be a rate regulator, not a planner of generation *or transmission designed to bring about the construction of preferred types of generation.* Indeed, FPA section 215 explicitly states that FERC may *not* order the construction of any generation or transmission asset.[119] FERC cannot order transmission providers to do what FERC itself has no authority to do, yet that is exactly what this final rule aims to do.

48. The final rule purports to order transmission planners to plan for a "predicted" generation mix in a distant future 20 years away, but the exact generation mix in 20 years is impossible to predict.[120] The real goal of this pretextual final rule is not to try the

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[118] *See, e.g.*, *CAISO v. FERC*, 372 F.3d at 400 (holding that FERC cannot prescribe the membership of the CAISO board, as FERC has authority over only "rates, charges, classifications, and closely related matters"); *see also Ari Peskoe*, *Replacing the Utility Transmission Syndicate's Control*, Energy Law Journal, Vol. 44.3 547, 578 (2023) (Peskoe Article) ("FERC's authority over utility 'practices' is best understood as referring to 'actions habitually being taken by a utility in connection with a rate found to be unjust and unreasonable.'") (footnote omitted), https://www.eba-net.org/wp-content/uploads/2023/11/8-Peskoe547-618.pdf.

[119] FERC regulates RTOs and RTO markets to ensure just and reasonable rates to consumers, but FERC has no authority to order a load-serving public utility to build a specific generation facility, only states can. *See* 16 U.S.C. 824(b)(1); *see also Hughes v. Talen Energy Mktg.*, 578 U.S. 150, 154 (2016) ("The States' reserved authority includes control over in-state 'facilities used for the generation of electric energy.'" (quoting 16 U.S.C. 824(b)(1))); *see also* 16 U.S.C.824o(i)(2) ("[Section 215 of the FPA] does not authorize the [Electric Reliability Organization, *i.e.*, NERC] or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or service."). Congress recently gave FERC a narrowly limited form of "backstop" siting authority for certain designated transmission lines, but that authority is not implicated in this final rule.

[120] PATH Concurrence at P 4 ("PATH graphically illustrates the inherent dangers in approving for regional cost allocation long-distance projects based on a prediction (*i.e.*, a guess) of what the generation mix will be in 20 years or more. PATH was originally part of the huge "Project Mountaineer" scheme—announced with great fanfare right here at the Commission itself – to build *three* high-voltage lines across hundreds of miles from West Virginia to East Coast load centers. The vast majority of the power to be delivered

impossible by predicting the generation mix in 20 years. Instead, the final rule is an attempt to become a national IRP planner and *bring about* a preferred generation mix through transmission planning by manipulating and shaping the future generation mix the special interests supporting this final rule want now.

49. The final rule denies that it is infringing on state authority reserved under FPA section 201, arguing, *inter alia*, that it directly regulates only those practices that affect the rates for the transmission of electric energy in interstate commerce and that it is not aiming to indirectly regulate any matter reserved to the states by FPA section 201.[121] The final rule is chock-full of "nothing to see here" rhetoric asserting that it does not seek to shape the generation resource mix, but merely responds to changes in the electric industry.[122] "Pay no attention to the [agenda] behind the [green] curtain!"[123] the final rule insists across 1300 pages. But it should be obvious by now that the final rule is just a pretext for enacting this administration's "net zero 2035" policy agenda, as well those of corporate and other special interests.[124] The true intent of the final rule is revealed by mandated categories of factors and minimum benefits, which drive the transmission development necessary to achieve the final rule's preferred generation resource mix. Any honest account of the final rule cannot ignore the monetary windfall it would shower

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along these lines was to be *coal*-generated. After running into a firestorm of opposition in both the states in the path (no pun intended), as well as the end-user load states, Project Mountaineer was abandoned except for the PATH project, which represented a segment of one of the proposed Project Mountaineer lines. That segment was never built either. Yet, consumers have been paying for it ever since. The lesson here is clear: For policy-driven long-distance, regional transmission projects affecting consumers in multiple states, it is absolutely essential that state regulators have the authority to approve – or disapprove – the construction of these lines *and* how they are selected for regional cost allocation *and* what that cost allocation formula is, if their consumers are going to be hit with the costs.") (emphasis in original).

[121] Final Rule, 187 FERC ¶ 61,068 at P 263; *see also, e.g.*, *id.* P 271 ("[T]he requirements in this final rule respect and do not unlawfully infringe on state authority. Rather . . . the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes.").

[122] *E.g.*, *id.* PP 129, 130, 254, 259-263, 266, 271, 275.

[123] You can decide for yourself whether the "green curtain" represents "green energy" or something else that's green.

[124] *See supra* Sections I, III.B.

on generation and transmission developers; it is no wonder, therefore, why they were among the strongest supporters for the final rule. Nor can any rational individual—unless living in the Land of Oz—reasonably deny the role the final rule plays in furthering this pretextual agenda.[125] In light of this backdrop, the final rule's repeated assertions that it does not seek to shape the country's resource mix are simply not credible. Contrary to the final rule's claims, in violation of FPA section 201, the final rule transforms the Commission into a national IRP planner to promote the construction of transmission lines to further the development of the final rule's preferred generation resources.

### C. The Final Rule Violates the Major Questions Doctrine

50. Courts generally look with suspicion on "cryptic" delegations of authority,[126] and they are generally skeptical of agencies that seek to find "elephants in mouseholes," or otherwise seek to rely on tiny grants of authority to justify major actions.[127] As the Supreme Court explained in *West Virginia v. EPA*:

> Where the statute at issue is one that confers authority upon an administrative agency, that inquiry must be "shaped, at least in some measure, by the nature of the question presented"—whether Congress in fact meant to confer the power the agency has asserted. In the ordinary case, that context has no great effect on the appropriate analysis. Nonetheless, our precedent teaches that there are "extraordinary cases" that call for a different approach—cases in which the "history and the breadth of the authority that [the agency] has asserted," and the "economic and political significance" of that assertion, provide a "reason to hesitate before concluding that Congress" meant to confer such authority.[128]

51. I invoked the major questions doctrine in my dissent to the proposed changes to the Commission's certificate policy, even before *West Virgina v. EPA* was handed down. In my dissent, I wrote that:

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[125] *See supra* nn.5, 8, 10, 13, 15, 16, 67.

[126] *See FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 160 (2000).

[127] *See West Virginia v. EPA*, 597 U.S. at 746-47 (Gorsuch, J., concurring) (quoting *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001)).

[128] *Id.* at 700 (internal citations omitted).

> "The federal government's powers . . . are not general[] but limited and divided. Not only must the federal government properly invoke a constitutionally enumerated source of authority to regulate in this area or any other, it must also act consistently with the Constitution's separation of powers. And when it comes to that obligation, this Court has established at least one firm rule: 'We expect Congress to speak clearly' if it wishes to assign to an executive agency decisions 'of vast economic and political significance.' We sometimes call this the major questions doctrine."
>
> In short, the major questions doctrine presumes that Congress reserves major issues to itself, so unless a grant of authority to address a major issue is explicit in a statute administered by an agency, it cannot be inferred to have been granted.
>
> . . .
>
> Yet the Supreme Court has made it clear that broad deference to administrative agencies on major questions of public policy is not in order when statutes are lacking in any explicit statutory grant of authority. "*When much is sought from a statute, much must be shown*. . . . [B]road assertions of administrative power demand *unmistakable legislative* support."[129]

52. The final rule's actions clearly implicate the major questions doctrine. If imposing a final rule intended to cost consumers literally trillions of dollars to build transmission projects designed to implement a sweeping policy agenda never passed by Congress is *not* a major question of public policy, then there is no such thing.[130]

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[129] *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,107 (2022) (Christie, Comm'r, dissenting at P 22-23 (quoting *Nat'l Fed'n of Indep. Bus. v. Dep't of Labor, OSHA*, 595 U.S. 109, 121-22 (2022) (Gorsuch, J., concurring); *In re MCP No. 165*, 20 F.4th 264, 267-68 (6th Cir. 2021) (Sutton, C.J., dissenting (emphases added))) (internal citations omitted) (Certificate Dissent), https://www.ferc.gov/news-events/news/items-c-1-and-c-2-commissioner-christies-dissent-certificate-policy-and-interim.

[130] *See* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, The New York Times, Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, "'I've called [the final] rule the *biggest energy policy in the country*.'" (emphasis added)), https://www.nytimes.com/2024/04/25/climate/energy-

53. Yet the final rule brushes aside arguments that it would not withstand scrutiny under the major questions doctrine.[131] Against these arguments, the final rule denies that its aim is to influence the generation mix;[132] asserts that it "neither transforms nor expands the Commission's authority; it merely applies existing authority;"[133] asserts that "the differences in transmission planning required by this final rule represent differences in degree, not kind, from the Commission's longstanding regulations;"[134] and asserts that its "incremental process improvements [from Order No. 1000], while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the 'vast economic and political significance' that would implicate the major questions doctrine."[135] None of these assertions are credible.

54. This final rule violates the major questions doctrine. As discussed above, it is axiomatic that Congress has not intended for the Commission to be a national IRP planner. On the contrary, it has left both the siting of transmission and the development of generation to the states.[136] Yet the final rule encroaches on these traditional state prerogatives in the absence of any explicit Congressional authorization to do so.

55. The final rule seeks to shape specific policy outcomes by mandating categories of factors and minimum benefits. In addition, the final rule does something else that also arguably makes it transformative. Citing, *inter alia*, *South Carolina,* the final rule declares that the Commission has exclusive jurisdiction over regional transmission planning and cost allocation processes:

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dept-speed-transmission.html.

[131] Final Rule, 187 FERC ¶ 61,068 at P 275.

[132] *Id.*

[133] *Id.* P 277.

[134] *Id.*

[135] *Id.* P 278 (quoting *West Virginia v. EPA*, 597 U.S. at 735 (J. Gorsuch, concurring)).

[136] *See supra* Section III.B. Since 2005, FERC has had very limited backstop siting authority for certain transmission projects that has never been used. *See generally Applications for Permits to Site Interstate Elec. Transmission Facilities*, Order No. 1977, 187 FERC ¶ 61,069 (2024).

> As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's *exclusive* jurisdiction.[137]

In fact, the *South Carolina* court did *not* state that the Commission has *exclusive* jurisdiction over regional transmission planning and cost allocation. In fact, that court noted, for example, that the Florida Public Service Commission is statutorily vested with authority to "plan[], develop[], and main[tain] . . . a coordinated electric power grid" throughout the state.[138]

56. Whether the Commission can exclusively supplant the states in transmission planning and cost allocation is a major question—particularly considering the enormous breadth of the transmission grid, the importance of electricity in everyday life, and the trillions of dollars in transmission investment (read, cost increases) this final rule intends to impose on consumers.[139] The final rule's conclusion that regional transmission planning and cost allocation processes are subject to the Commission's exclusive

[137] Final Rule, 187 FERC ¶ 61,068 at P 86 & n.184 (emphasis added) (citing *South Carolina*, 762 F.3d at 55-59, 84 (affirming the Commission's authority to regulate transmission planning and cost allocation as practices affecting rates); Order No. 1000-A, 139 FERC ¶ 61,132 at P 577 (holding that "requirements regarding transmission planning and cost allocation . . . are practices affecting rates.")); *see also id.* P 130 ("Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity *are the exclusive jurisdiction of the Commission*, we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential.") (emphasis added); *id.* P 770.

[138] *See, e.g.*, *South Carolina*, 762 F.3d at 62 n.3.

[139] *See FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016) ("It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level.").

jurisdiction suggests that the Commission "occupies the field"[140] in these areas.[141] But this is wrong. This pretextual final rule erodes the states' authority, which is inconsistent with the principle of cooperative federalism reflected in the FPA. Under the major questions doctrine, absent an act of Congress, the Commission may not usurp the powers of the states in this manner.

## IV. The Final Rule Fails Under Both Prongs of FPA Section 206

57. I cannot support the final rule because it has been fundamentally changed from the NOPR. In jettisoning essential components of the NOPR, the final rule has been reduced to a mere pretext for this supposedly *independent* Commission's effort to implement the current administration's "net zero 2035" policies. It will not produce rates that are just and reasonable and not unduly discriminatory or preferential. This final rule does not satisfy either of the requirements of FPA section 206. Under section 206, the Commission must first find that the rate on file is no longer just and reasonable and not unduly discriminatory or preferential. Then the Commission must find that a particular replacement rate would be just and reasonable and not unduly discriminatory or preferential.[142] The final rule fails on both counts.

58. Although the current regional transmission planning processes could be improved—they are certainly not in need of the final rule's *solutions*. Even if these solutions were the only way forward to reform regional transmission planning, an act of Congress would be necessary first because the final rule is far beyond the reach of the FPA. While the Commission might *prefer* a different rate, that preference alone does not make all the filed rates of every transmission provider unjust and unreasonable.

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[140] *See Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984) ("If Congress evidences an intent to occupy a given field, any state law falling within that field is preempted." (citation omitted)); *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 475-476 (4th Cir. 2014) ("Even where state regulation operates within its own field, it may not intrude indirectly on areas of exclusive federal authority." (quoting *Pub. Utils. Comm'n of State of Cal. v. FERC*, 900 F.2d 269, 274 n.2 (D.C. Cir.1990) (internal quotation marks omitted))).

[141] The final rule's determination here aligns with the final rule's complete gutting of the roles of the states in transmission planning and cost allocation. *See infra* Section IV.B.1.

[142] 16 U.S.C. 824e.

### A. The Final Rule Fails to Justify its Action Under Section 206

59. The final rule presents no justification for taking action *in this proceeding* against *all* of the filed transmission rates pursuant to FPA section 206. The record, while consisting of thousands of pages of comments, simply does not contain substantial evidence sufficient to make a generic showing that the existing filed rates of all transmission providers are unjust, unreasonable, unduly discriminatory or preferential.[143] In *South Carolina*, the D.C. Circuit explained that "the substantial evidence test" for a rulemaking proceeding "'requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.'"[144] Here, the final rule's "rel[iance] on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution"[145] fails because it relies on cherry-picked special interest comments to support the pre-baked and pretextual findings needed to enact the administration's preferential, and *discriminatory*, policy agenda as well those of corporate and other special interests.

#### 1. The Record Is Not Sufficient to Make a Generic Showing That Every Transmission Providers' Regional Transmission Planning and Cost Allocation Processes Are Unjust, Unreasonable, and Unduly Discriminatory or Preferential

60. The evidence in the record that is used to support the final rule's section 206 finding consists largely of comments from special interests that will profit from the final rule. The final rule also signals that there has been limited regional transmission development since Order No. 1000. This evidence should not be used to mean that every transmission provider in the country has transmission practices that are unjust and unreasonable.

61. The final rule declines to analyze the "justness and reasonableness of either generator interconnection processes or local transmission planning processes" in its survey of issues in regional transmission planning.[146] The final rule identifies benefits of

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[143] *See South Carolina*, 762 F.3d at 64-65 (citations omitted).

[144] *Id.* at 54 (quoting *Wis. Gas Co. v. FERC*, 770 F.2d 1114, 1156) (alterations in the original)).

[145] *See* Final Rule, 187 FERC ¶ 61,068 at P 132 (citing *South Carolina*, 762 F.3d at 67) (additional citation omitted).

[146] *Id.* P 111.

transmission planning.[147] The final rule states that "transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints."[148] The final rule states that transmission spending has increased, which turns into higher customer bills.[149] The final rule identifies projections are necessary for growing future transmission needs, including load growth[150] and changing reliability needs.[151] And supply is changing due to state policies, customer preferences, and utility preferences (the latter two can also be driven by state policies or by activist investor preferences).[152]

62. Translating FERC-speak, we are left with bland statements of the obvious: Transmission is expensive to build; transmission spending is up; generators front a lot of the needed money; consumers eventually pay them back; lack of regional integrated planning results in piecemeal transmission construction; this is inefficient and costs consumers more. Yet simply because a rate could be more efficient, that alone is not enough to make the filed rate unjust and unreasonable.

63. Many of the special interest commenters point to studies, projections, and reports that show that regional transmission planning could be done more efficiently.[153] When

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[147] *Id.* PP 90-91.

[148] *Id.* P 90.

[149] *Id.* P 92.

[150] *Id.* P 95.

[151] *Id.* PP 93-94.

[152] *Id.* PP 96-97.

[153] *See, e.g.*, Johannes Pfeifenberger, et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, at 48-49 (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf; Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 26-28 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf; Johannes P. Pfeifenberger, et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* (Apr. 2019), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_trans

we peel back the "green curtain" shrouding this final rule, however, we see that these comments are almost exclusively from self-interested entities which would gain substantially from the very Commission action that they support.[154] Indeed, the record being used to support the section 206 finding consists of special interests who are going to profit monetarily from the final rule, including generation developers, transmission developers, and corporate purchasers of preferred power.[155] None of these comments (individually or taken together) are sufficient to meet the high burden of proof that all transmission providers' tariffs are unjust and unreasonable due to the profit-seeking motivations behind them.

64. In addition, the final rule looks back over the period following Order No. 1000 and states that regional transmission planning processes have yielded only "limited investments in regional transmission planning projects."[156] Let's suppose that over the last decade a transmission developer had instead proposed massively expanding transmission while the load growth projections remained flat. Consumers commenting on that aggressive plan would have challenged it as gold-plating. Regulators would have rejected it as imprudent. The so-called "limited investments" were instead a sign of responsiveness to projections made during that era. Rather than seeing this outcome as a feature of considered ratemaking during a period of low load growth, the final rule attributes this lack of investment to the shortcomings of the existing regional transmission planning processes—meaning the tariff changes mandated by Order No. 1000.[157] For these reasons, the final rule's reliance on a lack of regional transmission development post-Order No. 1000 is not persuasive, especially to support the finding that all transmission providers' tariffs are unjust and unreasonable.

### 2. The Record Shows That Regional Planning Deficiencies Exist *Only* in Isolated Pockets

65. The evidence in this record does not demonstrate a single nationwide systemic problem. Rather, the record shows that the "deficiencies identified by the Commission 'exist[] only in isolated pockets.'"[158] The final rule even recognizes the many regions

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mission.pdf.

[154] Such commenters include ACORE, PIOs, ACEG, Advanced Energy Buyers, AEE, Renewable Northwest, SREA, and Clean Energy Buyers.

[155] *See* Final Rule, 187 FERC ¶ 61,068 at P 96.

[156] *Id.* P 101.

[157] *Id*.

[158] *See South Carolina*, 762 F.3d at 67 (quoting *Associated Gas Distribs. V. FERC*,

representing a substantial percentage of consumers where regional transmission planning is working.[159] The final rule points to the MISO Multi-Value Project transmission planning process as an effective example of regional transmission planning.[160] From this, it could be concluded that the final rule suggests that regional transmission planning is working in MISO, including on a long-term basis. It is logical to conclude similarly regarding CAISO's[161] and New York's regional transmission planning.[162] Vertically integrated monopoly public utilities have expanded their transmission capacity by engaging in integrated resource planning that is reviewed and approved by their state regulators.[163] NRECA, an organization representing both transmission providers and transmission-dependent entities, highlights that its members have observed regional transmission planning processes that range from successful to broken.[164] According to NRECA, some RTO regions are working, and others are not. NRECA similarly states that some non-RTO regions are working, and others are not.

66. This is hardly ironclad evidence sufficient to support a generic finding that the regional transmission planning processes are no longer just and reasonable. The record here shows that regional and multistate regional planning is happening in significant and large swaths of the country subject to our rate jurisdiction, including on longer-term

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824 F.2d 981, 1019 (D.C. Cir. 1987)) (alteration in the original).

[159] *See generally* Final Rule, 187 FERC ¶ 61,068 at PP 71-77.

[160] *Id.* P 102; *see* OMS Initial Comments at 2 (stating that "it is critically important to note at the outset that MISO's regional planning process already reflects many of the elements and features contained in the [NOPR], and it should be looked to as a model for other regions to emulate."); MISO Initial Comments at 1-2.

[161] CAISO Initial Comments at 3 ("The CAISO already engages in long-term planning, and its existing transmission planning process is consistent with the direction of the NOPR."); CAISO Reply Comments at 1-2 (stating that "the Commission should not unduly disrupt or undo existing planning processes and approaches that are functioning well and enabling transmission providers to plan for system needs efficiently and cost-effectively.").

[162] New York Commission and NYSERDA Initial Comments at 5.

[163] *See, e.g.*, Southern Companies Initial Comments at 13-15 (stating that its "IRP/RFP-driven transmission planning is successfully expanding their electric grid to address the changing resource mix and load"); Undersigned States Reply Comments at 6-7.

[164] NRECA Initial Comments at 14-16.

horizons, and that other regions have room for improvement. These circumstances are entirely different than those facing the Commission when it issued Order No. 1000. The factual justification for a single, national FPA section 206 finding is simply not present in the way it was for Order No. 1000. No amount of hand waving or misdirection can change the lack of sufficient evidentiary support for this Commission to take the sweeping national action pursuant to FPA section 206 in this rule. This significant deficiency leaves this *entire* exercise open to meaningful challenge.

### B. The Replacement Rate Is Not Just and Reasonable

67. Not only does the final rule fail to meet its evidentiary burden, but the replacement rate that the final rule imposes is not just and reasonable and has no basis in law. The final rule has removed any serious state role in agreeing to the final rule's planning and cost allocation processes, and the final rule fails to protect consumers as FERC is required to do under the FPA. Further, the cost causation principle cannot, and should not, extend as far as the today's final rule suggests, and should not require that the ratepayers of a non-consenting state pay costs of other states' public policies where there is mismatch between planning criteria and benefits.

#### 1. The Final Rule Reverses the States' Roles in Transmission Planning and Cost Allocation Promised by the NOPR

68. The main reason I supported the NOPR was that it "*formally* put the states — for the first time — at the center of regional transmission planning and cost allocation decision-making for policy-driven projects in *all* regional transmission entities, if the states choose."[165] Specifically, I explained:

> [F]or these [Long-Term Regional Transmission Facilities] the NOPR propose[d] to require the regional planning entities to consult with *and seek the agreement of* the relevant states to *both* the selection criteria for these projects *and* to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects — such as, for example, the "highway-byway" formula approved by the SPP Regional State Committee — or states

[165] NOPR Concurrence at P 5 (emphases in original) (footnote omitted).

> can agree to a process for a project-by-project agreement on cost allocation among one or several states — such as, for example, the State Agreement Approach in PJM — or states may choose some combination of both. States in a multi-state RTO or ISO can even agree to defer the decision on cost allocation to the governing board of the RTO/ISO. The result is, while we are proposing to require regional planning entities to study and evaluate a broad, forward-looking array of information — including information addressing states' individual energy policies and goals — any projects identified through this new process will not be built, or more importantly, paid for by consumers, until the states representing such consumers have agreed that such projects are indeed needed and wanted by those same consumers.[166]

I wrote about the advantages of elevating the role of the states:

> [E]levating the role in planning and cost allocation of state regulators — who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component — will make it more likely, not less, that necessary transmission can get built while ensuring that rates resulting from these types of policy-driven projects will not be unjust and unreasonable, which they clearly have the potential to be.[167]

The day the Commission issued the NOPR, some of my colleagues expressed similar sentiments.[168]

69. Unfortunately—perhaps emanating from the final rule's erroneous legal conclusion that the Commission has exclusive jurisdiction over regional transmission

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[166] *Id.* P 11 (emphases in original) (footnotes omitted).

[167] *Id.* P 14 (emphasis in original).

[168] *See supra* n.48; NOPR, 179 FERC ¶ 61,028 (Phillips, Comm'r, concurring at P 4) ("I support the proposal to require transmission providers to consult with and incorporate states' views in project selection and cost allocation. I invite comment on the value of such state involvement for increasing the likelihood that those facilities are sited and ultimately developed with fewer costly delays."), https://www.ferc.gov/news-events/news/item-e-1-commissioner-phillips-concurrence-building-future-through-electric.

planning and cost allocation[169]—the final rule completely eviscerates the states' role contemplated in the NOPR in both the transmission planning and cost allocation processes. Other than a few cosmetic gestures, the final role essentially treats the state regulators like other stakeholders in the RTO/ISO. But states are not mere "stakeholders:"

> State regulators have the duty to act in the *public interest* and states alone are sovereign authorities with inherent police powers to regulate utilities through their designated state officers. The FPA itself explicitly recognizes state authority. So it is perfectly fitting for state regulators to have the important roles proposed in this NOPR, without preempting the regional planning entities from seeking additional input through their existing stakeholder processes.[170]

The evisceration of the states' role in transmission planning and cost allocation and the relegation of state regulators to mere "stakeholder" status is alone reason enough for me to dissent.

### a. The Final Rule Undercuts the States' Role in the Transmission Planning Process

70. A major example of the final rule's undercutting of the states' role in the transmission planning process is with respect to the selection criteria. As a reminder, the selection criteria are a key component of the planning process because once a project is selected, money starts to flow from the ratepayers to transmission developers. Recognizing the states' important role in the planning process, the NOPR required that the states *approve* the selection criteria that transmission providers use in the planning process:

> Given the important role states play and the wide variety of potential approaches to selection criteria, we propose, as part of this requirement, that public utility transmission providers must consult with and seek support from the relevant state entities, as defined below, within their transmission planning region's footprint to develop the selection criteria.[171]

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[169] *See supra* Section III.C.

[170] NOPR Concurrence at P 13 (emphasis in original).

[171] NOPR, 179 FERC ¶ 61,028 at P 244; *see also* NOPR Concurrence at P 11 ("State approval is especially important in a multi-state region, where different states

To implement this requirement, the NOPR proposed "to require that public utility transmission providers demonstrate on compliance that they developed their proposed selection criteria in consultation with the relevant state entities in their transmission planning region's footprint."[172] And it was clear at that time exactly what that meant—*agreement, nothing less*.[173] However, the final rule outright undermines these requirements—and the states' role as a whole—by "clarifying" that state approval of the evaluation process and selection criteria is *not actually required*:

> We clarify that we require transmission providers to *seek support* from Relevant State Entities, but *do not require transmission providers to obtain their support*, before proposing an evaluation process and selection criteria on compliance.[174]

Starkly demonstrating how milquetoast the requirement for transmission providers to "consult with and seek support from" the states has now become under the final rule, the final rule even fails to require that transmission providers indicate in their compliance filings whether the states agree with their selection criteria proposal.[175] So, from the NOPR requiring state agreement, the final rule does not even require the states' views to merit mere mention. Adding insult to injury, the final rule specifies that "transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities."[176]

71. The final rule acknowledges that "Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and

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have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements.").

[172] NOPR, 179 FERC ¶ 61,028 at P 246.

[173] *See* NOPR Concurrence at P 11; *see also supra* n.48.

[174] Final Rule, 187 FERC ¶ 61,068 at P 996 (emphases added).

[175] *Id.* P 999.

[176] *Id.* P 962 (emphasis added).

other stakeholders collaborate to develop an evaluation process and selection criteria."[177] But the final rule emphasizes that transmission providers are ultimately the only ones responsible for transmission planning and complying with the obligations of the final rule, and it notes that achieving consensus may simply not be possible in every instance.[178] Neither explanation provides a sufficient rationale to justify undercutting the requirement for state approval when states alone have the inherent police power to regulate the utilities within their states. One cannot help but see this as part of the larger pretextual shell game the final rule seeks to accomplish. Sadly, this is one of many examples where the final rule provides for a little extra process involving the states to demonstrate ostensibly that the Commission is committed to the principle of cooperative federalism, but in substance, states are relegated back to mere stakeholders, whose input can simply be disregarded if inconvenient.[179]

72. Unfortunately, not only the states' role with respect to the selection criteria has been gutted. As I must continue emphasize,[180] by mandating categories of factors and minimum benefits, the final rule seeks to shape specific policies and outcomes, regardless of the consent of the states.[181] The goal of this pretextual final rule is to plan preferential policy and corporate-driven projects regardless of states' support. One must also ask whether the extent to which this final rule requires prescriptive planning processes also limits the states' role to participate meaningfully when most are resource-strapped.

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[177] *Id.* P 996.

[178] *Id.*

[179] *See supra* P 69.

[180] *See supra* Section I. Another example, of course, is micromanaging how local "stakeholder" meetings must be conducted, which, as noted, runs a strong risk of conflicting with state IRP proceedings and state authority. *See* Final Rule, 187 FERC ¶ 61,068 at PP 1625-1646. As above, I question whether prescriptive requirements to this degree can truly pass muster under court precedent.

[181] And transmission providers themselves cannot even voluntarily account for states' input in the planning. Today's final rule requires that transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Final Rule, 187 FERC ¶ 61,068 at P 962.

73. States did not join RTOs[182] to pay for these preferential policy and corporate-driven projects. Rather, as I wrote in my concurrence to the NOPR, "States joined to provide their retail consumers with the promised benefits of lower transmission costs and strengthened reliability through regional planning of core Reliability projects."[183] I speak from personal experience. When I was a Commissioner at the Virginia State Corporation Commission, my colleagues and I considered applications to permit Virginia's major utilities to join PJM. The Virginia Commission's rules required us to examine "among other things, an [RTO's] reliability practices, pricing and access policies, and independent governance."[184] When we voted to approve the applications, PJM's planning for public policy projects that would be cost allocated regionally was not even on our radar.

### b. The Final Rule Guts the States' Role in Cost Allocation as Proposed in the NOPR

74. Given the pretextual nature of this rule, it should not be surprising that it eviscerates the states' role in deciding cost allocation matters. NARUC strongly supported the NOPR's proposal to involve states in the cost allocation for Long-Term Regional Transmission Facilities and conversely disagreed with a requirement that transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from the states.[185] NARUC explained:

> [S]ince the projects under consideration in the Long-Term Regional Transmission Planning process are largely driven by state public policies, state regulators should have a key role in evaluating the benefits and allocating the costs. State regulators are attuned to the concerns of the local

[182] I am aware that states *qua* states do not join RTOs/ISOs. Rather, they use their regulatory power to allow or require their regulated transmission-owning utilities to join.

[183] NOPR Concurrence at P 13.

[184] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter concerning the application of Virginia Electric and Power Company d/b/a Dominion Virginia Power for approval of a plan to transfer functional and operational control of certain transmission facilities to a regional transmission entity*, Case No. PUE-2000-00551 (Nov. 10, 2004). The order included a stipulation in which Dominion agreed that joining PJM would not alter its legal obligation to seek a CPCN from the Virginia Commission to construct generation or transmission assets. *Id.*, Partial Stip. ¶ 6.

[185] NARUC Initial Comments at 45.

> communities where the transmission will be sited and the retail ratepayers who must, in many instances, foot a large fraction of the cost.[186]

Of course, to effectuate the pretextual agenda, the final rule simply ignores NARUC's entreaties and instead cuts the states out of any meaningful role in cost allocation.

75. First, the final rule essentially terminates the State Agreement Process by making the *ex ante* cost allocation method the default approach. While the NOPR proposed to require transmission providers to revise their OATTs to include *either* (1) an *ex ante* cost allocation method (*i.e.*, a Long-Term Regional Transmission Cost Allocation Method) to allocate the costs of Long-Term Regional Transmission Facilities, (2) a State Agreement Process, or (3) a combination thereof,[187] the final rule substantially modifies the NOPR proposal to require the use of one or more *ex ante* cost allocation methods.[188] Although the final rule permits transmission providers to include a State Agreement Process in their OATTs if the states agree, the final rule specifies that the State Agreement Process "cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities,"[189] and the final rule modifies the NOPR proposal to require an *ex ante* cost allocation method to apply as a backstop.[190] The *ex ante* cost allocation method backstop would apply if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and others *or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential*.[191]

76. Second, under the final rule, state consent on cost allocation is not required. The final rule explicitly declines to adopt the NOPR proposal to require transmission providers to seek the agreement of the states regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[192] Instead, the final rule merely requires transmission providers to establish a six-month Engagement

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[186] *Id.* at 46 (citations omitted).

[187] NOPR, 179 FERC ¶ 61,028 at P 302.

[188] Final Rule, 187 FERC ¶ 61,068 at P 1291.

[189] *Id.* PP 1292, 1361, 1404.

[190] *Id.* P 1292.

[191] *Id.* P 1293.

[192] *Id.* P 1354.

Period "to provide a forum" for the states to negotiate an *ex ante* cost allocation method(s) and/or a State Agreement Process.[193] Under the final rule, if the negotiations fail, transmission providers must still file an *ex ante* cost allocation method(s).[194] Worse still, the final rule specifies that, even if the states *do* reach an agreement on an *ex ante* cost allocation method(s) and/or a State Agreement Process, the transmission providers *may ignore* it and file their own *ex ante* cost allocation method(s) instead.[195] Similarly, the final rule declines to require that, if the transmission providers disagree with a proposed cost allocation method agreed on by the states, transmission providers must file both cost allocation methods: the transmission providers' preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities. So to the states, the final rule says, "Heads I win, tails you lose."

77. Further, under the final rule, at the end of the Engagement Period, the states' role—however small—in shaping an *ex ante* cost allocation formula is effectively over. NARUC argued that the Commission should provide some mechanism for future review of cost allocation methodologies for Long-Term Regional Transmission Facilities given that state public policies may evolve:

> As the name suggests, these transmission facilities are expected to be planned over a longer period of time than projects built for reliability or economic reasons. States that

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[193] *Id.* P 1357.

[194] *Id.* P 1367.

[195] *E.g.*, *id.* P 1359 ("[T]he ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers."); *id.* P 1429 ("[A]fter the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings. Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method *and not file a State Agreement Process or other ex ante cost allocation method to which Relevant State Entities agreed*. In addition, *we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree*, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.") (emphases added; footnote omitted); *see also id.* P 1356 n.2895 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (*Atlantic City*)).

> do not currently have public policies requiring extensive transmission investments may forego an opportunity to participate in discussions regarding cost allocation, but their public policies may evolve over time. For the reforms proposed in this NOPR to be successful, the positions of relevant state entities should not be frozen in time.[196]

But the final rule denies this request.[197] Further, the final rule specifies that transmission providers may file subsequent changes to their cost allocation method(s) *without establishing future Engagement Periods* beyond the initial one.[198]

78. As noted above, the upshot of these changes, taken together, is that the states are simply cut out of any significant role in the cost allocation of the of Long-Term Regional Transmission Facilities. The final rule completely eviscerates the State Agreement Process and renders it non-viable. The final rule eliminates the core element of that approach—that states enter such cost allocation arrangements *voluntarily*. Now—with an *ex ante* cost allocation method that must serve as a backstop in the event that the states' negotiations fail, looming over the states' heads like the sword of Damocles—the final rule gives states "an offer they can't refuse," telling the states that must they agree to a cost allocation or the transmission providers will impose one on them anyway. In such a circumstance, fruitful negotiation between the states is virtually impossible, as states simply cannot say "no." At the risk of stating the obvious, this forced cost allocation on the states is, of course, contrary to comments of NARUC and many of the individual states.[199]

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[196] NARUC Initial Comments at 49.

[197] Final Rule, 187 FERC ¶ 61,068 at P 1368.

[198] *Id.*

[199] *See* NARUC Initial Comments at 45 ("NARUC strongly supports the Commission's proposal to involve states in cost allocation for Long-Term Regional Transmission Facilities and conversely explicitly rejects a requirement that public utility transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from relevant state entities.") (footnotes omitted); *see, e.g.*, Alabama Commission Initial Comments at 9 ("In other words, states may not force their preferences on their neighbors, or compel them to subsidize their achievement. Thus, it goes without saying that Alabama ratepayers should not be required to pay for transmission projects that are designed to promote or facilitate the public goals of other states, localities, or entities."); West Virginia Commission Reply Comments at 2-3 ("The [West Virginia Commission] opposes any changes in transmission cost allocation that would require West Virginia customers, or

79. Just as concerning, as I discuss in Sections I and IV.B.2 of this dissent, the final rule will enable the ratepayers of non-consenting states to be assessed the cost of public policy projects of other states, which is anti-democratic and violates the basic principle of fairness. As NARUC points out, NARUC and individual state commissions supported the State Agreement Process to address this concern:

> NARUC is particularly supportive of the State Agreement Process, which is similar to the PJM State Agreement Approach that has been approved by FERC and that NARUC and state commissions advocated to be included in the final rule. A state agreement approach allows states to further their public policy goals without burdening the ratepayers of states that have different priorities.[200]

The final rule's gutting of the very State Agreement Process that NARUC supports as part of the final rule's choice to ignore the consent of the states on cost allocation removes this key protection for the states and their ratepayers.

80. Further, given the final rule's determinations undercutting the states' role, I highly doubt that PJM's State Agreement Approach or other existing mechanisms involving the states in other RTOs will remain viable with respect to the cost allocation of Long-Term Regional Transmission Facilities.[201] In addition to PJM's State Agreement Approach,

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customers of any State, to involuntarily pay for new transmission facilities that are needed to support the public policy generation choices of other States."); North Carolina Commission and Staff Initial Comments at 15-16 ("The [North Carolina Commission and Staff] strongly support the NOPR proposals regarding cost allocation for regional transmission facilities developed through the Long-Term Regional Transmission Planning process, as that term is defined in the NOPR, specifically the requirement for transmission providers to seek state agreement on cost allocation methodologies and the requirement to create an opportunity for states to negotiate a cost allocation method after a transmission facility has been selected through the Long-Term Regional Transmission Planning process."); Utah Commission Initial Comments at 9 ("[I]mposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of FERC's authority under Section 206.").

[200] NARUC Initial Comments at 51 (footnote omitted).

[201] PJM's State Agreement Approach exemplified the proper way to involve states in decisions regarding cost allocation for public policy projects. The PJM State Agreement Approach was not directed by Order No. 1000, but rather by PJM's own voluntary act of reaching out to the states in PJM States and asking PJM States to propose

NARUC notes that the country's other multi-state RTOs have mechanisms in place for the states to participate in regional transmission cost allocation:

> In many regions, state regulators are at the forefront of successful efforts to coordinate regional transmission, including what many understand to be the most challenging issue, cost allocation. For instance, in SPP, the Regional State Committee has the primary authority for setting the basis of any regional cost allocation. In both MISO and ISO-New England, state committees have the ability to propose alternative cost allocation methodologies under some circumstances.[202]

81. Specifically, SPP has a Regional State Committee (RSC) process by which the RSC has agreed to a "highway-byway" *ex ante* cost allocation and SPP will file it,[203] and MISO's Tariff provides that MISO will file under FPA section 205 OMS's alternative cost allocation to MISO's proposal.[204] Given that the final rule's determination that transmission providers may ignore any agreement or alternative proposed by the states,[205] such mechanisms could be called into question—unless the RTOs *voluntarily* agree to

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a cost allocation for public policy projects. PJM accepted PJM States' proposal—which became the PJM State Agreement Approach—and submitted it to FERC in its compliance filing. It was accepted by FERC, but as today's final rule shows, only grudgingly and only until the chance came to extinguish it.

[202] NARUC Initial Comments at 46 (citing MISO Transmission Owners Agreement, Appendix K, Article II, Section II.E.3.b (providing regional state committee with the opportunity to develop and request MISO file an alternative cost-allocation methodology under certain circumstances); ISO New England, Agreements and Contracts, Transmission Operating Agreement, Section 3.04 (h)(vi)(A-C) (providing regional state committee with opportunity to provide alternative cost allocation proposal in connection with certain transmission cost allocation provisions in ISO-NE's tariff)).

[203] *See* SPP, Governing Documents Tariff, § 7.2 (Bylaws 7.2 Regional State Committee) (2.0.0); *see also Sw. Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 219, *order on reh'g*, 109 FERC ¶ 61,010, at PP 93-94 (2004); *Entergy Arkansas, Inc.*, 133 FERC ¶ 61,211, at P 15 (2010).

[204] *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,165, at PP 30-31 (2013) (citations omitted).

[205] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 1359, 1429; *see also id.* P 1356 n.2895 (citation omitted).

preserve them in their OATTs.[206] If these mechanisms are weakened, or even eliminated, the only alternatives left for the states to shape the RTOs' cost allocation would be to file comments to the RTOs' cost allocation filings or to file a section 206 complaint—no different than any RTO stakeholder.

82. The final rule acknowledges that "experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states."[207] However, the final rule's determinations on cost allocation undercut this critical role. It appears obvious that the final rule does not in fact view the states as partners in a cooperative federal system, but rather as potential obstacles to its pretextual political, corporate, and ideological agendas.

83. The final rule sets forth two central arguments for its dramatic reduction of the states' role. First, the final rule suggests that, per *Atlantic City*,[208] the Commission cannot deprive transmission providers of their FPA section 205 filing rights to propose tariff changes to rates.[209] And second, the final rule claims that if transmission providers were permitted to rely solely on a State Agreement Process to determine the cost allocation and that process were to fail, "there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs," and "[a]s a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized."[210] Both arguments are without merit.

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[206] *See, e.g.*, *id.* P 1412 ("[N]or do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs); *id.* n.3013 ("[T]ransmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.").

[207] *Id.* P 124.

[208] 295 F.3d 1.

[209] *E.g.*, Final Rule, 187 FERC ¶ 61,068 at P 1363 & n.2909; *id.* P 1356 n.2895.

[210] *Id.* P 1293.

### *i.* The Final Rule Takes Far Too Broad a View of *Atlantic City*

84. *Atlantic City* is often discussed as a bar to FERC's ability to take meaningful action on many issues, including transmission cost allocation.[211] But *Atlantic City* does not stand for an outright prohibition on Commission action, especially under FPA section 206, under which this pretextual rule purports to act. All *Atlantic City* stands for is that "transmission-owning utilities have 'filing rights' under section 205 that FERC may not *revoke*."[212] *Atlantic City* does not prevent FERC from granting additional filing rights to other entities, including *state regulators*, if it determines that existing practices, including RTO independence, are unjust and unreasonable and unduly discriminatory or preferential.[213]

85. In a similar vein, *Atlantic City* does not require FERC to force non-consenting states to pay for other states' policy projects, as today's final rule implies.[214] The final rule's reliance on *Atlantic City* in this regard is simply a way for FERC to sidestep action that will truly ensure that needed transmission gets built with the cooperation, support, and assent of the states. Instead, what we have in today's final rule is a patent instance of

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[211] 295 F.3d at 9-11.

[212] *See also* Peskoe Article at 572 (emphasis added), a thorough and helpful distillation of the intricacies of FPA sections 205 and 206 as to RTO governance. *See also id.* at 567.

[213] *See id.* at 614-615 ("To bolster RTO independence, FERC could expand filing rights over regionally significant issues that are currently controlled by the [investor-owned utilities (IOUs)], such as *cost allocation for regional transmission expansion*. . . . State regulators are also potential beneficiaries. State utility commissions comprehensively regulate IOUs' local service and are familiar with IOUs' local operations and planning. *State filing rights might serve a consumer protection function, as state regulators are ultimately responsible for ensuring that retail rates, which include costs of RTO-planned transmission projects and RTO-administered markets, appropriately account for consumers' interests.* As noted, MISO and SPP agreements already provide state regulators with limited filing rights over transmission cost allocation or resource adequacy, two areas where states have overlapping oversight. . . . *Providing states with meaningful roles in RTO processes might mitigate future conflicts between states' priorities and RTO rules and planning processes*.") (emphases added) (footnotes omitted). Let me add my strong endorsement to granting states section 205 filing rights with respect to cost allocation. The final rule, of course, goes in the opposite direction.

[214] *See e.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 1356 n.2895, 1429-1431.

regulatory capture with the singular goal to build out preferential policy and corporate-driven projects, steamrolling the states and consumers alike. And to be clear, nothing meaningfully prevents the NOPR compromise that would have maintained or elevated the states' role in transmission planning and cost allocation even further. In fact, even accounting for *Atlantic City*, the NOPR compromise was a worthwhile solution to getting the transmission that is *actually* needed to serve organic load built.

#### ii. The Commission Fails Consumers by Unreasonably and Unfairly Socializing Policy- and Corporate-Driven Costs Across Captive Customers

86. The final rule's claim that the Long-Term Regional Transmission Facilities selected are "the more efficient or cost-effective solutions to Long-Term Transmission Needs"[215] is disingenuous. As I discuss above in Section I, in a sleight of hand move, the final rule lumps together in one bucket for planning and for cost allocation purposes projects that address policy-driven and corporate-driven needs with those that address reliability and economic needs. The final rule's goal is to socialize the costs associated with preferential policy and corporate-driven projects across the multi-state regions, even when the states have never consented for their consumers to pay for such projects. But requiring the ratepayers of a non-consenting state to pay for the public policy projects of another state cannot reasonably be deemed "efficient" or "cost-effective."

### 2. The Final Rule Requires Consumers in Non-Consenting States to Pay the Costs of Other States' Public Policy Projects

#### a. The Costs of Public Policy-Driven Projects Must Not be Imposed on Non-Consenting Consumers Without State Regulatory Oversight

87. In my NOPR Concurrence, I noted that "no individual state's consumers can be forced to bear the costs of another state's policy-driven project or element of a project against its consent."[216] I have adamantly maintained this position in subsequent Statements:

> The costs related to a public policy project . . . should be borne by the sponsoring state and not shifted to consumers in other states without the consent of responsible officials in those states, who can then be held accountable by the voters of that state for their decisions (as can officials in the

[215] *Id.* P 1293.

[216] NOPR Concurrence at P 12 (citing NOPR, 179 FERC ¶ 61,028 at PP 302, 312).

> sponsoring state). That is how democracy is supposed to work.[217]

I have explained that if the people and businesses of the sponsoring state do not like the impacts of their state's public policies, "their recourse is to the ballot box,"[218] but that in contrast, "[c]onsumers in other states do not have such recourse, which is why these costs must be confined to [the sponsoring state]."[219]

88. I have written before that "imposing the costs of a project driven by one state's public policies onto another state that has not consented to such cost allocation would, in my view, presumably result in unjust and unreasonable rates."[220] Such imposition would be contrary to basic fairness, a core principle of American democracy:

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[217] *N.Y. Power Auth.*, 185 FERC ¶ 61,102 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-nypas-abandoned-plant-incentive-el23; *N.Y. Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,004 (2022) (Christie, Comm'r, concurring at P 2).

[218] *E.g.*, *N.Y. Indep. Sys. Operator, Inc*., 178 FERC ¶ 61,101 (2022) (Christie, Comm'r, concurring at P 5), https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-independent.

[219] *N.Y. Indep. Sys. Operator, Inc*., 186 FERC ¶ 61,184 (2024) (Christie, Comm'r, concurring at P 2).

[220] *NSTAR Elec Co.*, 179 FERC ¶ 61,200 (2022) (Christie, Comm'r, concurring at P 10), https://www.ferc.gov/media/e-13-er22-1247-000; *see also N.Y. Indep. Sys. Operator, Inc*., 178 FERC ¶ 61,101 (Christie, Comm'r, concurring at P 6) ("A similar analysis could well lead to a different outcome in a *multi-state* RTO, if the record showed that the RTO was implementing one state's public policies as to preferred resources, and that implementation resulted in impacts being shifted to consumers in one or more other states in the multi-state RTO. *Such impacts and cost-shifting in multi-state RTOs, if proven by the record, could well be unjust, unreasonable and unduly discriminatory or preferential under the FPA*.") (emphasis in the original and added); *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110 (2021) (Christie, Comm'r, concurring at P 3) ("I also note that the NYISO is a single-state ISO and I have been able to locate no evidence in the record that the New York policies at issue in today's order are causing cost-shifting onto consumers in other states. *If consumers in other states were disadvantaged, I may well view this matter differently*.") (emphasis added), https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-state-public; *cf.* Commissioner Mark C. Christie, Fair RATES Act Statement on PJM Minimum Offer Price Rule (MOPR) Revisions, Docket No. ER21-2582-000 at P 6 (Oct. 19, 2021) ("I would have proposed that PJM formulate a

> For if democracy means anything at all, it means that the people have an inherent right to choose the legislators to whom the people grant the power to decide the major questions of public policy that impact how the people live their daily lives. . . . That is the basic constitutional framework of the United States and it is the same for any liberal democracy worth the name.[221]

The final rule subverts this principle.[222]

### b. Certain States Are Not "Cost Causers" for Cost Allocation Purposes

89. Today's final rule provides very little in the way of support for its cost allocation requirements, despite the extensive changes to planning requirements.[223] This final rule simply assumes that it is on sound footing as to cost causation. But that is not the case. While *some* precedent cited by today's final rule sheds some indirect light on the cost allocation issues implicated here,[224] at its core, today's final rule involves a new application of the cost causation principle to justify the final rule's pretextual agenda. It intends to force consumers in one state to pay for the costs of public policies enacted by politicians in another state and corporate purchasing preferences. But those costs and the resulting rates cannot be considered just and reasonable in any universe.

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replacement for the current MOPR based on three broad principles: (1) a state may designate specific or categorical resources as 'public policy resources' and such designated resources will be funded through a mechanism *chosen by the state* outside of the capacity market . . . and (3) *non-sponsoring state consumers would not be forced to pay for another state's designated public-policy resources*.") (footnotes omitted) (emphasis in the original and added), https://www.ferc.gov/news-events/news/commissioner-christies-fair-rates-act-statement-pjm-mopr.

[221] Certificate Dissent at P 63.

[222] *Infra* Section IV.B.2.b.

[223] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 266, 269, 279, 1304, 1478-1479.

[224] As an aside, I question whether some of the precedent cited by today's final rule in support of the cost causation issue is truly apposite when you look at the facts in those cases.

90. We are at the point where we must argue that not *all* consumers in certain states are "cost causers" simply because they have joined a multi-state RTO or fall within a transmission planning region. These consumers are not the "but for" cause of many of the Long-Term Transmission Needs required by the consideration of the specified categories of factors in today's policy agenda-driven rule. Nor are such consumers the intended beneficiaries of public policies in states enacted by politicians for whom they never voted. Indeed, absent rational limits on the "free rider" concept that the cost causation principle is meant to address, anyone can be deemed a beneficiary of any transmission project anywhere.

91. That policy-caused costs cannot be attributed to consumers who did *not* cause the policy is consistent with case law. As articulated mostly clearly by the D.C. Circuit, the cost causation principle means that "all approved rates [must] reflect to some degree the costs *actually caused* by the customer who must pay them."[225] This has been oft repeated by many courts over the years, including most notably the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) in *Illinois Commerce Commission v. FERC*.[226] The Seventh Circuit expanded on this further to state that, "[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[227]

92. Tied to the cost causation principle is the concept of "free ridership." As explained by the Commission in Order No. 1000-A, a free rider is an "entity is not required to pay for a benefit it receives"[228] and is the form of "subsidization" against which the cost causation principle is supposed to protect.[229]

93. As explained in Order No. 1000-A, the Commission treats each transmission customer not as using a single transmission path but rather as usual the entire

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[225] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (emphasis added).

[226] 576 F.3d 470, 476 (7th Cir. 2009) (*ICC*).

[227] *Id.*

[228] Order No. 1000-A, 139 FERC ¶ 61,132 at P 573.

[229] *Id.* P 578.

transmission system and views such service as service over the entire grid.[230] The Commission explained:

> Given the nature of transmission operations, it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. This is the essence of the "free rider" problem the Commission is seeking to address through its cost allocation reforms. Any individual beneficiary of a new transmission facility has an incentive to defer investment in the anticipation that other beneficiaries in the region will value the project enough to fund its development. This can lead to situations in which no developer moves forward, adversely affecting development of transmission facilities and, as a result, rates for jurisdictional services.[231]

Therefore, the Commission explained that the cost allocation provisions of Order No. 1000 (the failures of which allegedly justify the changes contemplated by today's final rule), which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, were consistent with the statement in *ICC* that "[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[232] Indeed, all of the precedent relied upon in today's final rule signals that free

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[230] *Id*. P 560 (citations omitted).

[231] *Id.* P 562 (internal citation omitted).

[232] *Id.* P 565 (citing *ICC*, 576 F.3d 470 at 476) (alterations in the original). In Order No. 1000, the Commission also found that "[b]eneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state's transmission needs driven by Public Policy Requirements." Order No. 1000, 136 FERC ¶ 61,051 at P 545. "If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits because Public Policy Requirements played a role in the decision to construct the transmission facility." *Id.* While Order No. 1000 may have successfully established this to be the case, per *South Carolina*, today's final rule is not similarly situated to Order No. 1000 with its required minimum benefits, selection criteria, and utter disregard of the states' role in planning and cost allocation. *See supra* Section III.A. Today's final rule

ridership is a concern solely based on the assumptions underlying the transmission planning. And herein lies the deception—the more you plan and account for, the bigger and more regionalized you can argue the cost allocation framework should be. Which makes sense when the goal of today's final rule is to enact a sweeping policy agenda and thus socialize the costs across consumers in a multi-state region.

94. The main support for the cost causation principle is *ICC*,[233] for the exact quote noted above. However, often omitted from the discussion of *ICC* is the context and outcome of the case. In that case, the Seventh Circuit remanded the Commission's approval of cost allocation concerning "Project Mountaineer"[234] (yes, the same one that prompted PATH) for lack of substantial evidence regarding the FERC-approved cost allocation. In addition to the quote above, the Seventh Circuit also expressed the following: "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, *or benefits that are trivial in relation to the costs sought to be shifted to its members*."[235] And it merits repeating that "[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, *as without the expectation of its contributions the facilities might not have been built, or might have been delay*ed."[236] So, given the extent to which the Long-Term Transmission Needs contemplated by today's final rule factor in state public policies and special interests' goals, you would expect the only beneficiaries for cost allocation purposes to be states with those public policies or other special interest drivers of the transmission.

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instead creates beneficiaries for projects that are primarily public policy-driven, based on the categories of factors required to be considered in today's final rule's planning requirements.

[233] 576 F.3d 470.

[234] *See* PATH Concurrence at P 4 (providing a history on Project Mountaineer). Relying on a case that remanded the Commission's *approval* of cost allocation associated with a regional transmission project that never came to fruition is nothing short of ironic.

[235] *ICC*, 576 F.3d at 476 (emphasis added).

[236] *Id.* (emphasis added). *See* NARUC Initial Comments at 33-34 ("Long-Term Regional Transmission Planning must recognize that benefits inherently become more speculative as the planning horizon increases. Additionally, planning based on public policy objectives must be transparent about identifying projects that would not be selected but for those public policy objectives. *Benefits assigned to projects must recognize these principles.*") (emphasis added).

95. Unfortunately, you would be wrong. Due to the final rule requiring planning for any and every transmission need and mandating minimum reliability and economic benefits as part of the planning process, projects developed primarily for preferential policy and corporate purposes will necessarily have the broadest array of so-called beneficiaries possible, all identified prior to selection.[237] These so-called beneficiaries will then be forced to pay for these projects, simply because they may receive some trivial benefits due to their participation in a regional transmission system. These so-called beneficiaries will be treated as "cost causers" even though their contributions *do not* ensure the projects get built nor ensure that the projects are not delayed. Today's final rule, of course, even emphasizes that, as to why today's final rule does not require the consideration of public policy benefits, it "does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities."[238] But this is because today's final rule already determined the minimum reliability and economic benefits that all projects contemplated by the final rule must have. Adding in public policy benefits would shift the resulting cost allocation to show the *actual* beneficiaries—the states with preferred policies and corporate and special interests. So, through a mismatch in planning criteria and benefits, today's final rule ensures socializing the costs of preferential policy and corporate-driven projects onto states and consumers that will ultimately receive trivial benefits, in violation of *ICC*. If you find all this confusing, the final rule is intended to be. That's why it's a shell game.

96. At its core, *ICC* is simply a baseline regarding the cost causation principle's application. That is, the Commission cannot require cost allocation to a particular group

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[237] *See supra* Sections I, III.A; *see also* Final Rule, 187 FERC ¶ 61,068 at P 965.

[238] Final Rule, 187 FERC ¶ 61,068 at P 1515. This is why I have described this final rule as a shell game with respect to the issue of the benefit mismatch between planning and costs. By making the minimum required benefits reliability- and economic-focused, today's final rule ensures that the "beneficiaries" are those that are receiving some reliability and economic benefits. As we know from basic transmission planning, *any* transmission built is going to bring some reliability and economic benefits. So, any transmission planned through Long-Term Regional Transmission Planning for the identified Long-Term Transmission Needs will necessarily bring some reliability and economic benefits. And by *not* requiring a matching of benefits to the Long-Term Transmission Needs that are planned for, in this case public policy benefits, the resulting benefits of any one project will be skewed to indicate more "beneficiaries" than there would be if today's final rule accounted for public policy benefits separately. *See* NARUC Initial Comments at 33-34. If today's final rule accounted for public policy benefits or corporate goals separately, it would be clear who the *actual* drivers, and *actual* beneficiaries, of any one project are.

of utilities, *i.e.*, consumers, where there is *no* evidence of benefits. Its findings should not be distorted, as today's final rule suggests through Orwellian newspeak, to support a mismatch of planning criteria to benefits to strongarm a cost allocation regime to get preferential policy and corporate-driven projects built.

97. Also referenced by today's final rule for cost causation is *South Carolina*.[239] In the context of cost causation, the D.C. Circuit concluded that "the Commission's adoption of a beneficiary-based cost allocation method is a logical extension of the cost causation principle."[240] The court added that it had "endorsed the approach of 'assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.'"[241]

98. The final rule does not simply require a beneficiary-based cost allocation, like Order No. 1000. Instead, as I *must continue to emphasize*, it requires mandating reliability and economic benefits during the planning process to shoehorn the broadest group of beneficiaries possible for projects that do not remotely relate to reliability and economic needs.[242] This is not a "light touch" that "does not dictate how costs are to be allocated."[243] Today's final rule may attempt to sequester the beneficiaries of these reliability and congestion benefits from the cost allocation "benefits" by not clearly linking the two,[244] but in what reality will a transmission provider seeking to comply with today's final rule identify *different* beneficiaries from those identified in the planning process? The result of this shell game is to ensure preferential policy and corporate-driven projects are selected with the widest group of beneficiaries possible, so as to socialize the costs across the widest group of consumers.[245]

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[239] 762 F.3d 41.

[240] *Id.* at 85.

[241] *Id.* (citations omitted).

[242] *See supra* Sections I, III.A.

[243] *See South Carolina*, 762 F.3d at 81; *see also supra* Section III.A.

[244] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at P 1506 ("We do not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission."). This provision illustrates the confusing and contradictory nature of the final rule and provides another example of the shell game.

[245] Today's final rule relies on several other cases in support of its oversimplification of the cost causation principle, such as *Old Dominion Electric Coop.*

99. Today's final rule ultimately presents the wrong solution to the perceived problem of "balkanized" transmission planning.[246] Unfortunately, today's final rule devises the shell game to ensure that the biggest planning bucket means the biggest pool of potential beneficiaries. And to carry out the shell game, the final rule walks back cost allocation principle (6) because, without this change, today's final rule's preferred cost allocation framework does not work.[247]

100. NARUC and many individual states oppose the Commission's imposition of mandatory minimum benefits and would prefer a bottom-up rather than a top-down approach: "The proposed list of benefits for consideration is a better way to accomplish the objectives of the NOPR than specification of benefits that must always be used in Long-Term Regional Transmission Planning."[248] Today's final rule blithely brushed these concerns aside.

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*v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018), and *Long Island Power Authority v. FERC*, 27 F.4th 705 (D.C. Cir. 2022), among others, but the same is true of these cases—the Commission cannot strong-arm beneficiaries to get transmission built, and override the states to do so. Of course, this is primarily a problem in multi-state RTOs, but overriding the states with regulation based on a cooperative federalism statute is not in good faith and the result is terrible for consumers everywhere.

[246] *See supra* Section IV.A.

[247] *See* Final Rule, 187 FERC ¶ 61,068 at P 1474.

[248] *See* NARUC Comments at 25; *see also* New York Commission and NYSERDA Initial Comments at 7 ("We urge the Commission to ensure that any final rule in this proceeding is sufficiently flexible to accommodate regional differences and avoid disrupting the processes already in place and otherwise underway in New York that are working well for the region."); SPP Initial Comments at 18 ("How and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each public utility transmission provider and its stakeholders. This would allow for agility in process decisions to balance the value the analysis provides with the burden of the effort."); ISO-NE Initial Comments at 5 ("Individual regions should be permitted to determine the benefits that will lead to transmission in the region."); NYISO Initial Comments at 39 ("The final rule should confirm that each planning region is not required to use the specific benefits described in the NOPR . . . . While, in practice, the NYISO already uses most of the 12 illustrative benefits identified in the NOPR, the NYISO should be permitted to retain its flexibility to identify, with input from state entities and stakeholders, the benefits used in its processes and how such benefits are calculated."); *id.* at 11 ("The final rule should not mandate strict requirements concerning how long-term transmission planning must be

101. To effectuate purported compliance with the cost causation principle, today's final rule ignores the principle of the *optimal solution* in transmission planning. For each identified reliability problem, there is an optimal solution that solves the reliability problem at the *least* cost to consumers. For an economic project, consumers should receive the *maximum* reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the *least* costs for the project. The final rule, by contrast, claims that a project that is driven by one state's public policies will still provide some reliability and congestion benefits to other states, so consumers in those states *must* be treated as beneficiaries.[249] But even assuming that consumers in those other states hypothetically receive some marginal reliability or congestion benefits, they are being overcharged for those benefits because the project includes the costs of another state's public policies or costs of projects to meet corporate goals, and the only benefits required to be considered by today's final rule are reliability and economic benefits. Consumers in the non-policy causing states are not receiving or paying for the optimal solution to an identified reliability problem or maximum congestion relief compared to the costs they are being forced to pay. As a consequence, the transmission *rates*—let's ignore the planning practices for a moment—they will be forced to pay are clearly unjust and unreasonable under the FPA.

### 3. The Final Rule Violates the Commission's Consumer Protection Duty Under the FPA

102. To add to the number of already unjust and unreasonable aspects in today's final rule, today's final rule is patently unfair to consumers. That much is apparent from its decision, through transmission planning and cost allocation processes: (1) to shift interconnection costs from generation developers to consumers through transmission planning, and (2) to shift the costs of, *inter alia*, a transmission project accommodating a corporate commitment from corporate consumers to other consumers. Today's final rule, equally harmful to consumers, walk backs the NOPR proposal to remove the CWIP Incentive, one of the major reasons I supported the NOPR in the first place. The final rule essentially uses the justification of efficiency and cost-effectiveness to create catastrophic outcomes for consumers. Such an anti-consumer outcome is simply unjust and unreasonable, and in this case, even unduly discriminatory and preferential.

conducted.").

[249] Final Rule, 187 FERC ¶ 61,068 at Section III.D.1.c.

### a. The Final Rule Unlawfully Shifts Interconnection Costs from Developers to Consumers

103. In prior statements, I have frequently discussed the basic principle that generation developers should pay the costs to interconnect their generators to the grid:

> [G]eneration developers in RTOs should pay the full "but for" costs of their interconnection, including network upgrades. Consumers (*i.e.*, load) should not pay one nickel. They are not the ones seeking to profit from the interconnection. New generation in RTOs is supposed to be driven by the market, not by integrated resource planning, as in non-RTOs. This is the compelling principle underlying participant funding of interconnection in RTOs.[250]

By requiring the coordination of regional transmission planning and generator interconnection processes and by requiring the incorporation of Factor Category Six: generator interconnection requests and withdrawals in the development of Long-Term Scenarios, the final rule causes consumers to subsidize generation developers and thus subverts this basic principle.

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[250] *See Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,190 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-order-concerning-funding; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,156 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-gia-order-concerning-funding; *Midcontinent Indep. Sys. Operator, Inc.*, 183 FERC ¶ 61,113 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-fsa-order-concerning-funding; *Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,225 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-and-fsa-orders-concerning-funding; *see also Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,182 (2023), *order on reh'g*, 187 FERC ¶ 61,015 (2024), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-order-rejecting-miso-gia-concerning-funding. This principle also applies to developers of merchant transmission lines who seek to interconnect. *Midcontinent Indep. Sys. Operator, Inc.*, 181 FERC ¶ 61,218 (2022) (Christie, Comm'r, concurring at P 1), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-funding-interconnection-costs-rtos. If state regulators in a multi-state region agreed on a different cost allocation related to interconnection costs that they believed protected consumers from unfair treatment, then such alternative would merit consideration.

### i. Coordination of Regional Transmission Planning and Generator Interconnection Processes Will Result in Unlawful Cost Shifts to Consumers

104. The final rule requires transmission providers in each transmission planning region to revise their existing Order No. 1000 regional transmission planning processes to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process.[251] As a result of this requirement, transmission providers may select in regional transmission plans for purposes of cost allocation transmission facilities designed to address certain interconnection needs and *will allocate the costs of such facilities to the load in that region*. This practice will force consumers to subsidize the interconnection costs of generator developers and in so doing turn them into the banks for the ventures, viable or otherwise, of generation developers — a classic example of the socialization of costs to enable private profit. Of course, this will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential.

105. The final rule's attempted justifications for this effort to shift interconnection costs to consumers are vacuous and fail to disguise the real agenda, which is to subsidize developers of preferred resources. For example, the final rule asserts that reforms are necessary because "it may be more efficient or cost-effective to address [interconnection-related transmission needs] through the regional transmission planning and cost allocation process."[252] The final rule professes that its requirements "will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation)."[253] But more efficient or cost-effective for whom? Certainly not for consumers who will be conscripted to subsidize tens or hundreds of millions of dollars of interconnection costs

[251] Final Rule, 187 FERC ¶ 61,068 at PP 1106-1107, 1126, 1145. Specifically, the final rule requires transmission providers to evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where, *inter alia*, "an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million." *Id.* P 1145 (emphasis in original).

[252] *Id.* P 1110.

[253] *Id.*

so that generator developers may more cheaply interconnect and make higher profits (and likely receive government subsidies). The final rule's speculation that extracting such subsidies from consumers will "facilitate access to lower-cost generation" is purely pretextual.

106. The final rule notes that "the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer."[254] Further, it asserts that the regional transmission facilities designed to address the interconnection needs "may have the potential to provide more widespread benefits to transmission customers."[255] Today's final rule does not even come close to justifying the enormous cost shifts this will place on consumers.

107. The final rule summarily brushes aside the concern that its reform will shift interconnection costs from interconnection customers (*i.e.*, generation developers) to load.[256] It explains that "[t]ransmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply."[257] The final rule also explains that "if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits."[258] But the regional cost allocation methods allocate cost only to load, not to generation. So, how could allocating interconnection costs to load enable them to be "roughly commensurate to benefits" when generator developers, the primary beneficiaries of the transmission facilities and *the "but for" cause* of their development be allocated nothing? Here, as elsewhere, the final rule deviates from the FPA's consumer protection purpose: under the final rule, rather than generation existing to serve load, load is being conscripted to serve (the profits) of generation.

108. Finally, the final rule's conclusion that it will not incentivize gaming by interconnection customers to include interconnection-related network upgrades in the

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[254] *Id.* (footnote omitted).

[255] *Id.* PP 1146-1148.

[256] *See id.* P 1117.

[257] *Id.*

[258] *Id.*; *see also id.* P 1110.

regional transmission planning process is detached from reality.[259] The final rule notes that interconnection requests require significant financial commitments from the interconnection customer (*e.g.*, application fees, study deposits, and site control requirements) and that interconnection customers employing such a strategy would face several risks.[260] As with so much FERC does, today's final rule woefully underestimates at its peril the profit-seeking, and at times, gambling behavior of generator developers. In issuing this final rule, the Commission appears to forget that a main driver in issuing Order No. 2023 was to *reduce* speculative interconnection requests and interconnection request withdrawals spurred by this behavior.[261] Despite the significant financial commitments and risks that the final rule describes, I can foresee generators submitting speculative or spurious interconnection requests in the efforts to be subsidized by load if the estimated interconnection costs are high enough. In any event, I think it obvious that, *ceteris paribus*, the final rule will encourage more disruptive *withdrawals*—particularly for requests that necessitate high interconnection costs—as the final rule provides generator developers dissatisfied with high interconnection costs a chance at another bite at the apple. And of course, apples taste sweeter when they're paid for by someone else.

### ii. Factor Category Six Will Result in Unlawful Cost Shifts to Consumers

109. For similar reasons, I oppose the final rule's requirement that transmission providers in each transmission planning region incorporate in the development of Long-Term Scenarios, Factor Category Six: interconnection requests and withdrawals.[262] Such a requirement would ultimately result in consumers paying for the transmission that generators need to interconnect to the grid. This again is a way to cost shift interconnection costs from generation developers to consumers.

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[259] *See id.* PP 1119-1120.

[260] *Id.* P 1119.

[261] *See, e.g.*, Order No. 2023, 184 FERC ¶ 61,054 at P 47 (stating that the existing serial first-come, first-served study process "create[d] incentives for interconnection customers to submit exploratory or speculative interconnection requests pursuant to which interconnection customers seek to secure valuable queue positions as early as possible, even if they are not prepared to move forward with the proposed generating facility. Such generating facilities are often not commercially viable and, thus, the interconnection customers ultimately withdraw from the interconnection queue.").

[262] *See* Final Rule, 187 FERC ¶ 61,068 at P 472.

### b. Factor Category Seven Forces Some Consumers to Subsidize Others

110. The Commission's requirement that transmission providers incorporate Factor Category Seven, utility and corporate commitments and federal, federally-recognized Tribal, state, and local goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios[263] is unjust and unreasonable because it will unfairly saddle consumers with unnecessary transmission costs that they *did not cause*. In addition, comments on Factor Category Seven identify several additional regulatory and practical obstacles that the final rule attempts to resolve by allowing transmission providers to dial the impact of these commitments and goals up or down.[264] Further, this provision is yet another count in the final rule's pattern of diminishing the states' role in regional transmission planning by elevating mere *corporate preferences* to have equal if not greater stature as the policy choices of states and federally-recognized Tribes.

111. It is worth starting the examination of Factor Category Seven simply by pulling the curtain back and highlighting the coalitions of comments that the final rule cites supporting it and opposed to it.[265] The strongest support for this provision comes from where we would all expect: the corporate interests with something to gain by shifting the costs that result from their preferential power purchase commitments to others along with the other special interests whose policy preferences have no place in developing a rate that is just and reasonable.[266] I am similarly unsurprised that the skeptics and opponents of this provision are led by retail rate authorities, load-serving entities from coast to coast,

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[263] *Id.* PP 481-484.

[264] *Id.* P 484.

[265] Commenters in favor include ACEG, AEE, Advanced Energy Buyers, Amazon, Breakthrough Energy, Center for Biological Diversity, Environmental Groups, Ørsted, PIOs, SEIA, and SREA. *Id.* PP 474-476. Commenters expressing qualified support include LADWP, MISO, and NRECA. *Id.* P 477. Commenters opposed include the Alabama Commission, California Commission, Duke, Illinois Commission, New York TOs, Pennsylvania Commission, PJM, and PPL. *Id.* PP 478-480.

[266] *See* James Downing, *FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming*, RTO Insider, Apr. 22, 2024 ("State renewable portfolio standards are not driving as much of the need for new transmission as the corporate renewable energy buyers that [Clean Energy Buyers] represents are, [Clean Energy Buyers Senior Director Bryn Baker] added."), https://www.rtoinsider.com/76831-ferc-experts-what-at-stake-transmission-rule-looming/.

and large multi-state RTOs. They understand that adopting Factor Category Seven is unfair, unworkable, and a mistake.

112. Factor Category Seven is as unlawful as it is unfair because it grossly violates cost causation principles of ratemaking.[267] Whether a corporate commitment or a state/Tribal policy goal is directly attributed to increased transmission costs, the entities with the self-imposed aspirations are the direct beneficiaries. Cost causation principles of ratemaking—not to mention reviewing courts—will dictate that those entities, and not any other transmission customer, are the beneficiaries of the resulting transmission built to accommodate the corporate commitments. As the direct beneficiaries, they will be responsible for the increased transmission costs driven by those commitments, goals, and preferences. Even worse, if one of these cost causers changes its commitment or goal, all of the transmission provider's customers could still be left paying for the increased costs that are *no longer attributable to any beneficiary*. This is not how a just or reasonable rate works.

113. Even if the unfair and unlawful Factor Category Seven is allowed to take effect, it will fail on its own terms for practical reasons. The final rule acknowledges that the corporate commitment or a state/Tribal policy goal are "more likely to change over the transmission planning horizon than factors in other required factor categories."[268] As a balm for this uncertainty, the final rule grants the transmission providers the discretion to apply the salve of a discount on the likelihood that any of these aspirations will come to pass. Nothing in the final rule will prevent transmission providers from discounting these commitments one hundred percent. This discount is simply an invitation for transmission providers to ignore Factor Category Seven.

114. Even worse, when a transmission provider expends its limited resources to read the tea leaves of corporate commitments and include them in the Long-Term Scenarios, that inclusion will result in a violation of the FPA. Applying the costs of one corporation's commitments to all of the transmission provider's customers amounts to undue discrimination against similarly situated customers *without* corporate commitments while bestowing an undue preference for those similarly situated customers *with* corporate commitments. Further, most utility customers are at a resource and access disadvantage to the deep-pocketed special interests (including the corporate commitments driven by their wealthy and sophisticated investor class) that enjoy influence and power. Rather than sticking the consumers with any part of the bill for the gold plating necessary for a different customer's corporate preferences, this Commission should not depart from its cost allocation precedent. Under that precedent, the beneficiaries are required to pay

[267] For a reminder on the shell game and how it seeks to use the cost causation principle, *see supra* Sections I, III.A, IV.B.2.b.

[268] Final Rule, 187 FERC ¶ 61,068 at P 484.

for the upgrades they are driving. This Commission should not now saddle less powerful people and small businesses with the costs of the choices made by influential corporations and their managers and investors.[269]

115. Let me be clear about how egregious and unfair this idea is with a hypothetical scenario. Suppose that a Fortune 500 company pressured by its investors commits to a corporate goal that it will only purchase electric power from certain preferred generation sources within a decade. It similarly commits to discriminate against power sourced from non-preferred generation resources. The transmission provider then informs the corporate customer that transmission upgrades will be necessary in order for those favored generation resources to actually deliver power to the corporate customer's facilities and to avoid receiving power from the non-preferred resources. Next, the transmission provider includes those upgrades in Factor Category Seven. Later, the transmission provider builds the necessary upgrades according to its regional transmission plan and incurs significant cost in doing so. Instead of attributing those costs to the corporate customer, the transmission provider socializes the upgrade costs to *all* of its customers. Rather than holding the actual cost causer accountable for the increase, the final rule instead dictates that the costs directly resulting from the customer's corporate commitment benefit *all ratepayers* because there are necessarily reliability and economic benefits that result from all transmission development. Then these increased costs are socialized across all of the transmission provider's customers. This realistic outcome is, to put it mildly, grossly unfair to consumers and a violation of the FPA.

116. Now suppose that a neighboring corporate customer (that receives an identical class of electric service as the customer in the prior hypothetical) announces in response its own corporate goal that it will never consider any factors other than reliability and cost in purchasing electric power because it wants to keep its costs as low as possible no matter what. How is a transmission provider supposed to accommodate that second corporate goal? Do the two commitments simply cancel each other out? Will the transmission provider carve out the second corporate customer? Where would that leave the customers who are silent with respect to these competing corporate goals? The final rule fails to answer these questions.

### c. The Final Rule Walks Back the NOPR Proposal to Remove the CWIP Incentive

117. Today's final rule also walks back the widely supported proposal to remove the CWIP transmission incentive. As I have discussed above, it is apparent that the

[269] I also have grave concerns that the final rule tasks transmission planning engineers to try their hands at becoming Wall Street analysts when they attempt to guess how serious any of the corporate commitments really are.

pretextual goal of this final rule is to get transmission built to serve political and corporate goals, no matter the cost and no matter who actually benefits from it.

118. As I noted on numerous occasions, a core principle of utility law and regulation for decades is that consumers can be forced to pay costs only for assets that are "used and useful" to them. In Order No. 679, the Commission determined that it may be necessary to depart from this long-standing ratemaking principle to "address the substantial challenges and risks in constructing new transmission."[270] And in my prior statements, I questioned, among other concerns, whether the Commission's determination of whether "substantial challenges and risks" exist when granting the various transmission incentives has becoming nothing more than a check-the-box exercise.[271] In particular, I noted:

> The Commission's incentive policies—particularly the CWIP Incentive, which allows recovery of costs *before* a project has been put into service—run the risk of making consumers "the bank" for the transmission developer; but, unlike a real bank, which gets to charge interest for the money it loans, under our existing incentives policies the consumer not only effectively "loans" the money through the formula rates mechanism, but also pays the utility a profit, known as Return on Equity, or "ROE," for the privilege of serving as the utility's *de facto* lender.[272]

119. The proposal to remove the CWIP Incentive was a major reason why I supported the NOPR, despite its flaws, and a massive step in the right direction to remedy the harm to consumers that these incentives have caused over the years.[273] However, instead of adopting the proposal to remove the CWIP Incentive, today's final rule chose to side with

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[270] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, at PP 26, 117, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[271] *See supra* n.61.

[272] February 2022 Concurrence at P 3 (emphasis in original); July 2022 Concurrence at P 3 (citation omitted); *see also* NOPR Concurrence at P 15 ("CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer . . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does."), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-e-1-regional-transmission-planning-and-cost.

[273] *See supra* PP 18-19.

developers and special interest groups, rather than with consumers. Today's final rule rationalizes the decision to walk back the removal of the CWIP Incentive by finding that any action on the CWIP Incentive is more appropriately considered in a separate proceeding where incentives can be comprehensively evaluated for all regional transmission facilities.[274] I regard that as nothing more than an excuse for a continuing failure to act.

120. Many commenters share my concerns that the CWIP Incentive inappropriately shifts risks to ratepayers and runs afoul of the core principle of utility law and regulation that consumers should pay costs only for assets that are "used and useful" to them.[275] Others argue that removing the CWIP Incentive may mitigate the risk of overbuilding that may result from the other changes cemented in today's final rule.[276] Today's final rule, however, is astoundingly silent on the consumer impact of retaining the CWIP Incentive.

121. Unfortunately, this is simply a continuation of the Commission punting on any meaningful reevaluation of transmission incentives. In my three years on the Commission, there has been *no* action to reevaluate the check-the-box award of transmission incentives, and it is far past time for me to begin dissenting from this lack of action on the Commission's part to change this shameful status quo.[277] By walking back the removal of the CWIP Incentive, today's final rule reveals, one again, its failure to protect consumers as required by the FPA.

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[274] Final Rule, 187 FERC ¶ 61,068 at P 1547.

[275] *See, e.g.*, California Commission Reply Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4-9; NARUC Initial Comments at 55-56 (referencing PATH and that the Commission granted several transmission incentives, resulting in a 14.3% return on equity); NASUCA Initial Comments at 8-9; North Carolina Commission and Staff Initial Comments at 17-18; North Dakota Commission Initial Comments at 6; Ohio Commission Federal Advocate Initial Comments at 15-16; Ohio Consumers Initial Comments at 29-31; OMS Initial Comments at 14-15; Pennsylvania Commission Initial Comments at 17-18; PJM States Initial Comments at 13; Virginia Attorney General Reply Comments at 3-4.

[276] *See, e.g.*, Massachusetts Attorney General Initial Comments at 24-25; North Carolina Commission and Staff Initial Comments at 17-18; Pennsylvania Commission Initial Comments at 17-18; PJM States Initial Comments at 13.

[277] *See, e.g.*, *Baltimore Gas & Elec. Co.*, 187 FERC ¶ 61,030 (Christie, Comm'r, dissenting at P 6).

## V. Conclusion

122. Had the states been given the authority to protect their consumers, as promised by the NOPR, I would have supported this rule just as I voted for the NOPR, as an imperfect but acceptable compromise.[278] If transmission projects that are planned to implement public policies—the product of *political* decisions made by politicians—or to implement corporate "green energy" power purchasing preferences—the product of corporate management and investors—are going to be included in long-term planning *mandated* by FERC, then the states must have the authority to consent to (i) the planning criteria (which determines which projects go into regional plans and receive cost recovery from consumers), *and* (ii) the formula for regional cost allocation of such projects.

123. This role for the states is not only essential but fair: fair to state policymakers and regulators and fair to the tens of millions of consumers they represent. The final rule, however, denies states that essential role and that denial renders this order unfair to the states and unfair to tens of millions of consumers.

124. As has been said before, denial is not just a river in Egypt. The short-sightedness of the final rule and the special interests who lobbied this Commission to deny states this key role is a denial of the reality of how transmission actually gets built in the union of states that is the United States of America. As a former state regulator who voted to approve scores of transmission projects, both regional and local, I will testify from experience that to get transmission built—especially the big, controversial regional lines of 500 kV and above—the states should not be dismissed as annoying obstacles that must be pushed out of the way by an omnipotent, omniscient FERC. Rather, state regulators must be respected as potential partners and, most importantly, *advocates* of such controversial lines, who will be invested in them and work to get them sited and built within their borders. That will never happen if states are denied the role that I advocated in the NOPR, that of full partners in deciding how, when and whether their consumers are burdened with costs for politically and corporate-driven policy projects.

125. This final rule could have corrected the single biggest flaw in Order No. 1000: the exclusion of the states from decision-making roles in FERC-mandated regional transmission planning for public policy projects. Instead, the final rule doubles down on that error with a blizzard of new planning mandates to serve political, corporate, and ideological agendas, while leaving the states with no real power to protect their consumers from the trillions of dollars of costs that this order brazenly wants to impose on them. The final rule is nothing but a pretext for enacting a sweeping policy agenda that Congress never passed. As such, it blatantly violates the major questions doctrine.

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[278] To reiterate what I said earlier: If I agree to get a root canal with anesthetic but learn upon arrival at the dentist's office that I still get the root canal but no anesthetic, that is not the original deal.

In producing rates that will be unjust, unreasonable, and unduly discriminatory and preferential, it violates the actual text of the FPA. And in that violation, it fails to fulfill our most important duty under the FPA, which is to protect consumers.

For these many reasons, I respectfully dissent.

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Mark C. Christie
Commissioner

189 FERC ¶ 61,126
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM21-17-001; Order No. 1920-A]

# Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

(Issued November 21, 2024)

**AGENCY**: Federal Energy Regulatory Commission.

**ACTION**: Order on rehearing and clarification.

**SUMMARY**: In this order, the Federal Energy Regulatory Commission addresses arguments raised on rehearing, sets aside, in part, and clarifies Order No. 1920, which required transmission providers to conduct Long-Term Regional Transmission Planning to ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs. Order No. 1920 also directed other reforms to improve coordination of regional transmission planning and generator interconnection processes, require consideration of certain alternative transmission technologies in regional transmission planning processes, and improve transparency of local transmission planning processes and coordination between regional and local transmission planning processes.

**DATES**: The changes to Order No. 1920 made in this order on rehearing and clarification will be effective on **[INSERT DATE 30 DAYS AFTER DATE OF**

**PUBLICATION IN THE FEDERAL REGISTER]**

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189 FERC ¶ 61,126
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Willie L. Phillips, Chairman;
Mark C. Christie, David Rosner,
and Judy W. Chang.

| | | |
|---|---|---|
| Building for the Future Through Electric Regional Transmission Planning and Cost Allocation | Docket No. | RM21-17-001 |

# ORDER NO. 1920-A

# ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING, SETTING ASIDE PRIOR ORDER, IN PART, AND GRANTING CLARIFICATION

(Issued November 21, 2024)

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## I. Executive Summary

1. In Order No. 1920,[1] the Federal Energy Regulatory Commission (Commission)

[1] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost*

revised the *pro forma* Open Access Transmission Tariff (OATT) to adopt reforms to its existing electric transmission planning and cost allocation requirements pursuant to section 206 of the Federal Power Act (FPA).[2] The Commission found that existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because, *inter alia*, the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs;[3] (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider a set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[4] Order No. 1920 addressed these deficiencies by establishing requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential including, *inter alia*, requiring transmission providers to conduct Long-Term Regional Transmission Planning[5] that will ensure the identification, evaluation, and selection of more efficient or cost-effective regional

*Allocation*, Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068 (2024).

[2] 16 U.S.C. 824e.

[3] *See infra* Introduction and Background section (defining "Long-Term Transmission Needs").

[4] Order No. 1920, 187 FERC ¶ 61,068 at P 1.

[5] *See infra* Introduction and Background section (defining "Long-Term Regional Transmission Planning).

transmission facilities to address Long-Term Transmission Needs, as well as the just and reasonable allocation of the costs of those facilities. By expanding the time horizon and scope of Commission-jurisdictional regional transmission planning processes, Order No. 1920 reflected an evolutionary step in the Commission's ongoing commitment[6] to ensure that those processes remain just and reasonable and meet the needs of the American people.

2. In this order, we refine and improve Long-Term Regional Transmission Planning by building on the reforms adopted in Order No. 1920, with a particular focus on ensuring that states have a robust role in Long-Term Regional Transmission Planning and cost allocation processes established in this rule. We continue to find, as the Commission did in the final rule, that the key components of Order No. 1920 together ensure that transmission providers will conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes. At least once every five years, transmission providers are required to conduct Long-Term Regional

[6] *See Preventing Undue Discrimination & Preference in Transmission Serv.,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, 118 FERC ¶ 61,119 (2007), *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009); *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

Transmission Planning, a process that includes looking ahead over a 20-year transmission planning horizon. This process further requires developing at least three plausible and diverse Long-Term Scenarios[7] that are based upon known drivers of transmission needs and informed by best available data; analyzing the impacts of events like extreme weather under each Long-Term Scenario; and evaluating potential Long-Term Regional Transmission Facilities.[8] This evaluation includes assessing whether these facilities would yield reliability and economic benefits to transmission customers and, if so, identifying those benefits. Together, these reforms ensure that transmission providers, state regulators, and stakeholders possess the information necessary for each transmission planning region to identify, evaluate, and select (i.e., determine whether to pursue the development of facilities) more efficient or cost-effective transmission facilities that provide significant benefits for customers.

3. Here, we adopt a number of modifications and clarifications to address the concerns raised in response to Order No. 1920. Order No. 1920 recognized the important role that states will play in Long-Term Regional Transmission Planning and established various requirements to facilitate their participation in those processes, including requiring transmission providers to engage with states in developing cost allocation approaches for Long-Term Regional Transmission Facilities. With this order, we

[7] *See infra* Introduction and Background section (defining "Long-Term Scenario").

[8] *See infra* Introduction and Background section (defining "Long-Term Regional Transmission Facility").

reaffirm and enhance that finding by recognizing that meaningful engagement with states is critical to the success of the Long-Term Regional Transmission Planning reforms established in Order No. 1920. Specifically, in response to rehearing and clarification requests, we better integrate states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. These modifications and clarifications address many of the concerns raised in the rehearing requests submitted in response to Order No. 1920, and they will increase the likelihood that Long-Term Regional Transmission Planning results in efficient and cost-effective transmission investment.

4. In this order, we also clarify what this rule does, and does not, require. Because Order No. 1920 mandates only improvements to transmission planning *processes* which, in turn, ensures foundational transparency about potential transmission development, Order No. 1920 does not force or mandate the development of certain transmission facilities. A requirement to develop a structured process to analyze *whether* building certain transmission facilities would yield benefits greater than their costs, over the long term and based upon various future scenarios, will help transmission providers and states to assess the value that those projects could bring. However, such process-based requirements are not the same as a requirement to build any particular transmission facilities. More precisely, Order No. 1920 does not require transmission providers to select any particular transmission facility; does not automatically authorize transmission developers to develop or construct any specific facilities; and does not mandate any

specific set of transmission customers to pay for any particular transmission facilities. Instead, Order No. 1920 and this order together set out processes that direct transmission planning regions to systematically consider various drivers of transmission needs and develop cost allocation approaches that yield the development of cost-effective transmission projects and thereby yield just and reasonable rates for customers.

5. As such, Long-Term Regional Transmission Planning as required by Order No. 1920 is a significant step forward in the Commission's responsibility to ensure just and reasonable and not unduly discriminatory or preferential rates. By establishing minimum standards based on transmission planning best practices observed around the country for forecasting future scenarios and managing the uncertainty inherent in forward-looking planning, the Long-Term Regional Transmission Planning requirements established in this proceeding will lead transmission providers to re-direct investment toward more efficient or cost-effective regional transmission facilities, and ultimately produce greater benefits for transmission customers.

6. Moreover, improving regional transmission planning practices is an urgent concern in light of the uncontroverted, rapidly changing circumstances on the grid, including load growth; the increased impacts of extreme weather; affordability concerns; and changing economics and policies that shape the resource mix and demand, which are increasing the need for transmission across the country. To cost-effectively meet these needs, Order No. 1920 and this order set out systematic processes that transmission providers will use to identify and analyze transmission projects that bring benefits to consumers, while recognizing the need for flexibility to account for regional differences.

7. Order No. 1920 follows in the footsteps of Order Nos. 890 and 1000 when it comes to the requirements governing the selection of potential regional transmission facilities identified through Long-Term Regional Transmission Planning. Consistent with the core theory of Order Nos. 890 and 1000, even though Order No. 1920 does not require the buildout of specific transmission facilities, it will reveal the benefits of designing and developing transmission projects and enable investment in those that yield great benefits for electricity customers across the country. Ultimately, we expect Order No. 1920 to lead to the development of more efficient or cost-effective transmission facilities through improved analysis and transparency that empower the transmission planning regions with the information needed to make prudent investments in beneficial transmission infrastructure for customers.

8. Order No. 1920's requirements for regional cost allocation practices are similarly well grounded in Commission and court precedent. If more efficient or cost-effective Long-Term Regional Transmission Facilities are identified and determined to be worth developing as a result of the enhanced regional transmission planning required by Order No. 1920, customers will pay for these facilities *only to the extent that they benefit* from them. That is because Order No. 1920 requires, consistent with well-established law and Orders No. 890 and 1000, that any cost allocation must comply with cost causation and the "beneficiary pays" principle.[9] Thus, Order No. 1920 will not lead one group of

[9] *See PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063, at P 66 (2007) (requiring PJM to set forth a "beneficiary pays" method in its tariff and consistently apply that approach each time a new regionally-planned transmission facility is approved), *on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61,082 (2008), *remanded Ill.*

customers to pay for more than their fair share of the costs of transmission development because any proposal to charge customers for costs that are not "roughly commensurate" with the benefits they are expected to receive from Long-Term Regional Transmission Facilities would contravene the final rule.[10]

9. Order No. 1920 builds on Order No. 1000's cost allocation requirements. Order No. 1000 required transmission providers to incorporate into their tariffs a default ("*ex ante*") cost allocation approach that, *if* transmission facilities are determined to be worth investing in based upon the results of the regional transmission planning process, would provide a mechanism for those transmission customers that benefit to pay for those projects. Prior to Order No. 1000, transmission providers did not necessarily have the means to charge transmission customers located within a particular transmission planning region, but outside their individual service territories, for the costs of regional transmission facilities that benefit customers throughout the region. Thus, the requirement to establish an *ex ante* cost allocation method in each OATT that would apply if a regional transmission planning process resulted in the selection of more

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*Com. Comm'n v. FERC*, 576 F.3d 470, 474-78 (7th Cir. 2009) (*ICC v. FERC I*) (remanding Commission order for further proceedings in light of Commission's failure to provide substantial evidence supporting Commission's approval of cost allocation method as complying with "beneficiary pays" principle).

[10] *See ICC v. FERC I*, 576 F.3d at 477 (holding that, if the Commission cannot quantify the benefits of particular transmission facilities to a particular class of transmission customers, it must have "an articulable and plausible reason to believe that the benefits [of those facilities] are at least roughly commensurate with" the costs to be paid by those customers).

efficient or cost-effective transmission facilities was central to ensuring that those facilities could actually be developed. Like Order No. 1000, Order No. 1920 requires each transmission provider to establish at least one *ex ante* cost allocation method through which the costs of Long-Term Regional Transmission Facilities will be allocated in a manner consistent with the "beneficiary pays" principle. Just like in Order No. 1000, the requirement to establish a mechanism by which the costs of selected transmission facilities may be allocated to relevant benefitting transmission customers does not mandate any particular method that transmission providers or planning regions must adopt.

10. Importantly, Order No. 1920 provides *additional flexibility* to transmission providers and states regarding cost allocation. While transmission providers under Order No. 1000 must adopt a cost allocation method for each type of transmission facility, Order No. 1920 relaxes this requirement. Furthermore, the modifications and clarifications granted on rehearing expand states' critical role in determining the cost allocation approach most suitable for each transmission planning region. These modifications and clarifications are necessary because the Commission recognizes that states play a critical role in the successful planning of, the decision about how to pay for, and ultimately, the deployment of beneficial regional transmission facilities.

11. For example, under Order No. 1920 as modified in this order, Relevant State Entities have an opportunity to negotiate their preferred *ex ante* cost allocation method(s) in the first instance, including being able to secure an extension of time if needed to continue those negotiations. Upon reaching agreement, Relevant State Entities can

present their preferred approach to the transmission provider, which then will either propose that approach to the Commission in its compliance filing for this rule, or if the transmission provider submits a different proposal, will include in its compliance filing the states' preferred approach for the Commission to consider.

12. This order further improves states' ability to negotiate cost allocation methods. Under Order No. 1920, states, through Relevant State Entities,[11] have an opportunity to secure the right to negotiate alternate cost allocation methods in the future, for either an individual transmission facility or a group of them, instead of using the *ex ante* cost allocation method on file in transmission providers' OATTs. This State Agreement Process[12] allows Relevant State Entities to consider, for example, whether certain Long-Term Regional Transmission Facilities largely provide a unique set of benefits such that the costs of those facilities are appropriately paid for in a different manner than under the *ex ante* cost allocation method. And, going forward, we require transmission providers to consult with Relevant State Entities regarding potential future changes to *ex ante* cost allocation methods and State Agreement Processes used in Long-Term Regional Transmission Planning.

13. Order No. 1920 provides greater flexibility than Order No. 1000 to deviate from the *ex ante* cost allocation method or to establish more than one *ex ante* cost allocation

[11] *See infra* Introduction and Background section (defining "Relevant State Entity").

[12] *See infra* Introduction and Background section (defining "State Agreement Process").

method. We also provide new opportunities for states to influence each of these choices because better enabling state input into cost allocation choices helps to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities that are likely to be sited and constructed only with state regulatory approval are ultimately developed successfully. Given that Order No. 1920 continues to afford considerable flexibility to transmission providers and Relevant State Entities to determine the cost allocation methods appropriate for their transmission planning region and retains the core obligation that any cost allocation method filed must be consistent with cost causation, the beneficiary pays principle, and other statutory requirements, we believe that cost allocation under this rule will result in just and reasonable rates. Order No. 1920 requires no more than Order No. 1000—that some mechanism for charging customers for more efficient or cost-effective transmission facilities be available in case such facilities are determined, after evaluation through Long-Term Regional Transmission Planning, to be worth developing. In fact, Order No. 1920 expands the opportunities for transmission providers, state regulators, and stakeholders to ensure that the costs of Long-Term Regional Transmission Facilities are allocated only "roughly commensurate" with the benefits expected to result from those facilities.

14. As noted above, we agree with certain arguments raised on rehearing and/or clarification of Order No. 1920. The instances where we modify the discussion in Order No. 1920 and set aside the result of Order No. 1920 generally fall into three categories. First, as discussed above, we further enhance the role of Relevant State Entities in Long-Term Regional Transmission Planning, especially their role in shaping the development

of Long-Term Scenarios and cost allocation methods. Second, we clarify that, when Relevant State Entities request, transmission providers must develop a reasonable number of additional scenarios to help inform the development or application of cost allocation methods. And third, we remove the requirement that transmission providers include corporate commitments in Factor Category Seven.

15. In the first category, Order No. 1920 provided an opportunity for states to influence how transmission is planned and ultimately paid for. This order goes even farther by agreeing with the rehearing arguments advanced by several states seeking additional and expanded opportunities for states to engage. Specifically, we require transmission providers to incorporate input from states about how Long-Term Scenarios used in Long-Term Regional Transmission Planning will be developed, particularly given that these scenarios will necessarily reflect how the states plan to meet their laws, policies, and regulations. In addition, we require transmission providers to include in the transmittal or as an attachment to their Order No. 1920 compliance filings any *ex ante* cost allocation method and/or State Agreement Process agreed to by the Relevant State Entities (to the extent the transmission provider does not adopt such an agreed-to cost allocation method and/or process as its own proposal), along with any information related to the Engagement Period[13] requested by a Relevant State Entity to be included. We are further persuaded by arguments on rehearing that Relevant State Entities may, in some cases, need time beyond the six-month Engagement Period allowed under Order

[13] *See infra* Introduction and Background section (defining "Engagement Period").

No. 1920. We therefore clarify that the Commission will grant extensions of time requested by Relevant State Entities where there is a showing that additional time is needed to resolve cost allocation discussions, up to a period of an additional six months. We believe this clarification ensures states who are engaged in working toward agreed-upon cost allocation methods and/or a State Agreement Process will have the time they need to resolve those discussions.

16. Furthermore, to ensure that Relevant State Entities have a role in cost allocation for Long-Term Regional Transmission Facilities going forward, we require that transmission providers consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, to amend that method or process. Finally, we clarify that the flexibility Order No. 1920 affords to transmission providers and Relevant State Entities to determine cost allocation methods appropriate for their region does not preclude proposed methods that allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation, e.g., based on the incremental costs and benefits of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations.

17. In the second category, we clarify in response to requests for rehearing that, while transmission providers are obligated to develop three Long-Term Scenarios that meet all of the requirements of the rule, Order No. 1920 permits transmission providers to develop

additional analyses, including other scenarios, to help inform who pays for those selected facilities. We further modify Order No. 1920 on rehearing to now require that transmission providers develop a reasonable number of additional scenarios at Relevant State Entities' request. The aim of Order No. 1920 is to ensure that transmission providers engage in the sufficiently long-term, forward-looking, and comprehensive transmission planning that is essential to have the information necessary to determine which investments are worth making. As long as transmission providers engage in that robust planning process and achieve the transparency required through that process, transmission providers can develop and consider additional information beyond that required as part of Long-Term Regional Transmission Planning.

18. In the third category of changes, on rehearing we modify, in one respect, the requirement to use seven categories of factors in the development of the three Long-Term Scenarios that are used to identify Long-Term Transmission Needs, and potential solutions to those needs. Several parties raise concerns regarding the inclusion of corporate commitments in Factor Category Seven, which they argue may elevate the needs of particular transmission customers above those of others. Upon further consideration, we eliminate the requirement to incorporate corporate commitments from Factor Category Seven into each Long-Term Scenario and thus we eliminate the potential for confusion around the treatment of particular transmission customers, while enabling transmission providers to give appropriate weight to corporate commitments as an indicator of customer preference in a region where those preferences are known.

19. Taken together, we believe the requirements of Order No. 1920 with the modifications and clarifications we make on rehearing will remedy the deficiencies of current regional transmission planning processes, establish sufficiently long-term, forward-looking, and comprehensive transmission planning, and ensure that transmission providers and Relevant State Entities in each region have the flexibility to devise cost allocation methods that reasonably and fairly assign the costs of Long-Term Regional Transmission Facilities to those that benefit from such facilities.

## II. Introduction and Background

20. In Order No. 1920, the Commission found that existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to:[14] (1) perform a

[14] Section 201(e) of the FPA, 16 U.S.C. 824(e), defines "public utility" to mean "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." As stated in the Order No. 888 *pro forma* Open Access Transmission Tariff (OATT), "transmission provider" is a "public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (*TAPS*), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002); *Pro forma* OATT section I.1 (Definitions). The term "transmission provider" includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators

sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs;[15] (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[16]

21. Order No. 1920 therefore established requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. First, Order No. 1920 required transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[17] Order No. 1920 established specific

(ISO).

[15] For purposes of Order No. 1920, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in Order No. 1920, running scenarios and considering the enumerated categories of factors. Order No. 1920, 187 FERC ¶ 61,068 at P 299.

[16] Order No. 1920, 187 FERC ¶ 61,068 at P 1.

[17] *Id.* P 224. Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. *Id.* For purposes of Order No. 1920, and consistent with Order No. 1000, a transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. *Id.* P 2 n.7; *see* Order No. 1000, 136 FERC ¶ 61,051 at

requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning, including, among other things, the use of Long-Term Scenarios to identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities[18] to meet those needs.[19]

22. Order No. 1920 required transmission providers to measure and use at least seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning.[20] Order No. 1920 required transmission providers to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service

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P 160.

[18] For purposes of Order No. 1920, a Long-Term Regional Transmission Facility is a regional transmission facility that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs. Order No. 1920, 187 FERC ¶ 61,068 at P 250. For the purposes of Order No. 1920, and consistent with Order No. 1000, a regional transmission facility is a transmission facility located entirely in one transmission planning region. An interregional transmission facility is a transmission facility that is located in two or more transmission planning regions. A local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation. *Id.* P 41 n.58 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 482 n.374).

[19] *Id.* P 298. For purposes of Order No. 1920, Long-Term Scenarios are scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs. *Id.* P 302.

[20] *Id.* P 719.

date of the transmission facilities and required that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[21]

23. Order No. 1920 required transmission providers to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.[22] Further, Order No. 1920 required transmission providers to include in their OATTs a process to provide Relevant State Entities[23] and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet transmission providers' selection criteria.[24] Order No. 1920 also required transmission providers to include in their OATTs provisions that require transmission providers—in certain

[21] *Id.* P 859. The Commission recognized that some transmission planning regions may include Long-Term Regional Transmission Facilities, or a portfolio of such Facilities, in a regional transmission plan, but may not necessarily include these Facilities for purposes of cost allocation. *Id.* P 3 n.8 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 63). For purposes of Order No. 1920, unless otherwise noted, when referencing Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected, we intend that the word "selected" mean that those Facilities are selected in the regional transmission plan for purposes of cost allocation. *Id.*

[22] *Id.* P 911.

[23] For the purposes of Order No. 1920, a Relevant State Entity is any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state. *Id.* P 1355.

[24] *Id.* P 1012.

circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected.[25]

24. Order No. 1920 required transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods[26] to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected.[27] Order No. 1920 further allowed, but did not require, transmission providers to adopt a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities.[28] Where Relevant State Entities agree to such a State Agreement Process, and transmission providers choose to file such a process, a State Agreement Process would provide Relevant State Entities up to six months after selection for its participants to determine, and transmission providers to file, a cost allocation method for specific Long-Term Regional Transmission Facilities.[29] Order No. 1920 also established a six-month time period (Engagement Period), during which transmission

[25] *Id.* P 1048.

[26] For purposes of Order No. 1920, a Long-Term Regional Transmission Cost Allocation Method is an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. *Id.* P 1291.

[27] *Id.*

[28] *Id.* P 1402. For purposes of Order No. 1920, a State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected. *Id.*

[29] *Id.*

providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities.[30]

25. Order No. 1920 required transmission providers to evaluate for potential selection in their existing Order No. 1000 regional transmission planning processes regional transmission facilities that will address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process.[31]

26. Order No. 1920 required transmission providers to consider more fully the alternative transmission technologies of dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning and cost allocation processes.[32]

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[30] *Id.* P 1354.

[31] *Id.* PP 1106-1107.

[32] *Id.* P 1198.

27. Order No. 1920 required transmission providers to adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities.[33]

28. Order No. 1920 required transmission providers to revise their interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in Order No. 1920.[34] Order No. 1920 also required transmission providers to meet additional information sharing and transparency requirements with respect to their interregional transmission coordination processes.[35]

[33] *Id.* PP 1625, 1677.

[34] *Id.* P 1751.

[35] *Id.*

29. The Commission received 49 timely filed requests for rehearing and/or clarification[36] and several additional filings.[37] The rehearing requests raise issues related to nearly all reforms adopted in Order No. 1920.

30. Pursuant to *Allegheny Defense Project v. FERC*,[38] the rehearing requests filed in this proceeding may be deemed denied by operation of law. However, as permitted by

[36] Appendix A provides the short names of the entities that filed requests for rehearing or clarification. To the extent that they intend to seek rehearing, the pleadings filed by Grid United, PJM States, Vermont Commission, and Virginia and North Carolina Commissions are deficient because they fail to include a separate section entitled "Statement of Issues" listing each issue presented to the Commission in a separately enumerated paragraph that includes representative precedent on which the participant is relying, as required by Rule 713(c)(2) of the Commission's Rules of Practice and Procedure (18 CFR 385.713(c)(2)). Consistent with Rule 713, we deem these petitioners to have waived the issues for which they seek rehearing. We consider petitioners' requests for clarification and, to provide clarity, address their arguments on rehearing below. EEI, PJM States, and PJM Utilities filed answers to certain requests for rehearing. Rule 713(d)(1) (18 CFR 385.713(d)(1)) prohibits an answer to a request for rehearing. Accordingly, we deny EEI's, PJM States', and PJM Utilities' motions to answer and reject their answers. Although PJM States style their July 3, 2024 pleading as comments, we treat the pleading as an answer to PJM's request for rehearing. *See, e.g.*, *San Diego Gas & Elec. Co*., 133 FERC ¶ 61,014, at P 15 (2010) ("[W]e are not obligated to accept a filing solely on the basis of its party-bestowed title. Instead, we examine the substance of the pleading.").

[37] Susann Rizzo, Gary Andrews, and Cher Gilmore filed letters supporting Order No. 1920. They also urged the Commission to require interregional transmission planning and establish environmental justice liaisons. In addition, E. Andrews, Illinois Commission, and Minnesota Commission each submitted late-filed pleadings that are generally supportive of Order No. 1920. Further, on June 12, 2024, Missouri Commission filed a letter addressing Order No. 1920. On September 3, 2024, Chairman Willie Phillips responded to the Missouri Commission letter. On July 22, 2024, State Regulatory Commissioners filed a letter expressing views on Order No. 1920. On October 9, 2024, Chairman Willie Phillips responded to the State Regulatory Commissioners' letter.

[38] 964 F.3d 1 (D.C. Cir. 2020) (en banc).

section 313(a) of the FPA,[39] we are modifying the discussion in Order No. 1920, setting aside the order, in part, and clarifying the order, as discussed below.[40]

31. Specifically, we set aside the order, in part, to specify that: (1) transmission providers are not required to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs;[41] (2) Factor Category Seven no longer includes corporate commitments;[42] (3) transmission providers must propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than two years from the date on which they will commence the first Long-Term Regional Transmission Planning cycle;[43] (4) when Relevant State Entities agree on a Long-Term

[39] 16 U.S.C. 825*l*(a) ("Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

[40] *Allegheny Def. Project*, 964 F.3d at 16-17. In Appendix B, we provide the revisions to the provisions of Attachment K to the *pro forma* OATT made in this order on rehearing and clarification.

[41] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 301 ("Transmission providers must use [the set of seven required benefits] to help to inform their identification of Long-Term Transmission Needs.").

[42] *See id.* P 481 ("We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios.").

[43] *See id.* P 1072 ("Thus, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence

Regional Transmission Cost Allocation Method or State Agreement Process resulting from the Engagement Period, transmission providers must include that method or process in the transmittal or as an attachment to their compliance filing, even if transmission providers propose a different Long-Term Regional Transmission Cost Allocation method or do not propose to adopt a State Agreement Process along with any information that Relevant State Entities provide to transmission providers regarding the state negotiations during the Engagement Period;[44] and (5) transmission providers shall consult with Relevant State Entities prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

32. Additionally, we grant multiple clarifications on most elements of Order No. 1920, as further discussed below. For example, among other clarifications, we clarify that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State

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the first Long-Term Regional Transmission Planning cycle.").

[44] *See id.* P 1359 ("We note, however, that the ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.").

Agreement Process(es), and that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion to those benefits.

33. Finally, we specify that the Commission will grant an extension of the required Engagement Period for up to an additional six months when Relevant State Entities request an extension and represent to the Commission that they agree, consistent with their chosen method to reach agreement, that they need additional time to finish cost allocation discussions. If the Commission grants such an extension request, it will also, as appropriate, extend, *sua sponte*, the relevant Order No. 1920 compliance deadlines to ensure that any extension of the Engagement Period would not conflict with the required compliance deadlines.

## III. The Overall Need for Reform

### A. Order No. 1920

34. In Order No. 1920, the Commission found substantial evidence to support the conclusion that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential. Specifically, the Commission explained that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements causes transmission providers to fail to adequately anticipate and plan for future system conditions and to fail to appropriately evaluate the benefits of transmission

infrastructure.[45] The Commission found that this status quo results in piecemeal transmission expansion to address relatively near-term needs and causes transmission providers to make relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. One result of this dynamic, the Commission explained, is that transmission customers overpay to meet their transmission needs and forgo benefits that outweigh their costs, which results in less efficient or cost-effective transmission investments. Such deficiencies, the Commission found, render Commission-jurisdictional regional transmission planning and cost allocation processes unjust, unreasonable, and unduly discriminatory or preferential.[46]

35. The Commission explained that it has the authority to issue Order No. 1920 under FPA section 206, which "instructs the Commission to remedy 'any . . . practice' that 'affect[s]' a rate for interstate electricity service 'demanded' or 'charged' by 'any public utility' if such practice 'is unjust, unreasonable, unduly discriminatory or preferential.'"[47] The Commission concluded that the D.C. Circuit has recognized that regional transmission planning and cost allocation processes are practices affecting rates subject to

[45] Order No. 1920, 187 FERC ¶ 61,068 at P 85.

[46] *Id.*

[47] *Id.* P 86 (citation omitted) (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55).

the Commission's exclusive jurisdiction[48] and that transmission providers use those processes to "determine which transmission facilities will more efficiently or cost-effectively meet" transmission needs, the development of which directly impacts the rates, terms, and conditions of Commission-jurisdictional service.[49] The Commission found that, because these processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates, they directly affect those rates.[50] The Commission found that, because such regional transmission facilities lead to a more robust transmission system, regional transmission planning and cost allocation processes, as well as "the rules and practices that determine how those [processes] operate,"[51] directly affect rates that customers pay for *both* transmission and sale of electric energy in interstate commerce.[52] The Commission noted that it may act pursuant to FPA section 206 if the Commission first establishes, through substantial evidence,[53] that existing practices are unjust, unreasonable, or unduly

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[48] *Id.* (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-59, 84).

[49] *Id.* (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56).

[50] *Id.*; *see also id*. P 86 n.186 (citing *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 485 (D.C. Cir. 2009)).

[51] *Id.* P 86 (quoting *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 279 (2016) (*EPSA*)).

[52] *Id.* (citing 16 U.S.C. 824e(a)).

[53] *Id.* (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 54). The Commission explained that FPA section 206 empowers the Commission to address the mere *threat* of unjust and unreasonable rates and, in this context the Commission need not necessarily provide *empirical* evidence for every proposition to satisfy the substantial evidence

discriminatory or preferential and, second, establishes that the replacement practices are just and reasonable.[54]

36. Addressing whether existing rates, or practices affecting rates, remain just and reasonable—i.e., the first prong under FPA section 206[55]—the Commission found that existing Order No. 890 and Order No. 1000 transmission planning and cost allocation requirements do not result in regional transmission planning that is conducted on a sufficiently long-term, forward-looking, and comprehensive basis, and transmission providers therefore often do not identify, evaluate, or select more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs.[56] The Commission determined that this results in piecemeal, inefficient, and less cost-effective transmission planning, which imposes real costs on customers[57] and renders the Commission's existing transmission planning and cost allocation requirements unjust,

standard. Order No. 1920, 187 FERC ¶ 61,068 at P 86 n.189 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64-65, 85).

[54] *Id.* (citing 16 U.S.C. 824e(a); *EPSA*, 577 U.S. at 277).

[55] *See Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 13 (D.C. Cir. 2021) (explaining that section 206 "mandates a two–step procedure" whereby the Commission, on the first step, must make an explicit finding that the existing rate is unlawful and then, on the second step, must set a new rate. (quotation omitted)).

[56] Order No. 1920, 187 FERC ¶ 61,068 at P 87.

[57] *Id.*

unreasonable, and unduly discriminatory or preferential in violation of FPA section 206.[58]

37. The Commission also found that existing transmission planning and cost allocation requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates. Thus, pursuant to FPA section 206, the Commission stated that it is now requiring transmission providers to engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs. The Commission found that such reforms will facilitate a process by which transmission providers can better identify, evaluate, and select more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs, which will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[59]

### 1. The Transmission Investment Landscape Today

38. The Commission explained that due to continuing changes in the industry, ongoing investment in transmission facilities is necessary to ensure the transmission system remains reliable, affordable, and economically efficient. More comprehensive transmission planning can enable transmission providers to proactively identify potential reliability problems and economic constraints and evaluate potential transmission

[58] *Id.* P 88.

[59] *Id.* P 89.

solutions, which can facilitate the selection of more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.[60] Transmission infrastructure can also increase competition among generators, which results in a host of benefits for customers, including cost savings from greater access to low-cost power.[61]

39. The Commission cited evidence demonstrating a nationwide increase in transmission spending since the issuance of Order No. 1000 and explained that, unsurprisingly, transmission costs have become an increasing share of customers' overall electricity bills in regions that saw a significant increase in transmission expenditures.[62] Further, the Commission highlighted several studies in the record demonstrating that transmission investment is likely to increase substantially in coming years.[63]

40. The Commission found that a number of factors are driving the growing need for new transmission infrastructure.[64] First, the Commission found that longer-term reliability needs are changing and driving a significant shift in the demands placed on the transmission system, and transmission system operators are increasingly depending on regional transmission facilities to ensure operational stability and system reliability, particularly due to the growing frequency of extreme weather events and increasing share

[60] *Id.* P 90 (citations omitted).

[61] *Id.* P 91.

[62] *Id.* P 92 (citations omitted).

[63] *Id.* P 93 (citations omitted).

[64] *Id.* P 94 (citations omitted).

of variable resources entering the resource mix.[65] Second, after many years of flat or minimal load growth in regions across the country, the Commission found that both regional and national demand is projected to increase significantly in the coming decades, which will require an increasingly robust transmission system to serve this growing load reliably. Third, the Commission found that supply is changing, driven by federal, federally-recognized Tribal, state, and local policies, customer demands, utility commitments, and the shifting economics of resources that comprise the resource mix.[66]

41. The Commission also found that the record in this proceeding affirms the Commission's longstanding recognition that regional transmission planning that identifies more efficient or cost-effective transmission solutions helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions, while inadequate or poorly designed transmission planning processes can cause customers to foot the bill for piecemeal, inefficient, and less cost-effective transmission solutions.[67]

42. Based on its experience implementing Order No. 1000, the Commission found that existing regional transmission planning processes are not of sufficient scope and duration to adequately or consistently identify transmission needs and associated opportunities to evaluate and select, on a more comprehensive basis, more efficient or cost-effective

[65] *Id.* (citations omitted).

[66] *Id.* PP 96-99 (citations omitted).

[67] *Id.* P 100 (citations omitted).

transmission solutions to those needs.[68] The Commission explained that, in some regions, investment in regional transmission facilities has declined as compared to prior to Order No. 1000 and that, across all non-RTO/ISO regions, not a single transmission facility has been selected pursuant to the regional planning processes since implementation of Order No. 1000. The Commission noted that, within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process occur, much of that investment has been in transmission projects that only address immediate reliability needs.[69] The Commission also cited evidence showing that, in the limited instances in which transmission providers have followed processes that share many of the elements that Order No. 1920 requires, customers have seen clear and quantifiable benefits.[70]

43. Further, the Commission explained that a substantial amount of new transmission investment is occurring in generator interconnection processes and local transmission planning processes, which, unlike regional transmission planning processes, do not comprehensively assess either broader transmission needs or solutions to those needs. The Commission concluded that overreliance on those processes can result in relatively

[68] *Id.* P 101.

[69] *Id.* (citations omitted).

[70] *Id.* P 102.

inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[71]

44. The Commission cited evidence showing a sharp growth in both the total cost of interconnection-related network upgrades and in the cost of such upgrades relative to generation project costs, as well as evidence showing that increases in interconnection costs are being driven, in many cases, by an expansion in the scope and complexity of interconnection-related network upgrades.[72] The Commission noted that, unlike regional transmission planning processes, the generator interconnection process is not designed to consider how to address transmission needs more efficiently or cost-effectively beyond the discrete interconnection request (or requests) being studied.[73] The Commission found that increasingly relying on interconnection customers' interconnection-related network upgrades to expand the capacity of the transmission system is inefficient and leads to less cost-effective transmission development than would result from long-term, forward-looking, and more comprehensive regional transmission planning, to the detriment of customers.[74]

45. The Commission also cited evidence that, since the issuance of Order No. 1000, the majority of investment in transmission facilities has been in local transmission

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[71] *Id.* P 103 (citations omitted).

[72] *Id.* PP 104-105 (citations omitted).

[73] *Id.* P 106.

[74] *Id.* P 108.

facilities, a trend that is accelerating across multiple regions.[75] The Commission noted evidence that transmission expansion through local transmission planning and in-kind replacement processes is incremental and misses the potential to identify, evaluate, and select more efficient or cost-effective transmission facilities to solve transmission needs, as well as to afford system-wide benefits that may not be achieved through piecemeal, one-off local transmission facilities.[76] Such transmission planning, the Commission stated, results in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[77]

### 2. Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes

46. The Commission concluded that there is substantial evidence in the record to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis.[78] The Commission found that the absence of a sufficiently long-term, forward-looking, and

[75] *Id.* P 109.

[76] *Id.* P 110 (citations omitted).

[77] *Id.* The Commission acknowledged the important roles played by generator interconnection processes and local transmission planning processes and underscored that the Commission's findings were not intended to call into question the justness and reasonableness of either process. *Id.* P 111.

[78] *Id.* P 112.

comprehensive regional transmission planning process results in relatively unfavorable outcomes, including: piecemeal transmission expansion to address relatively near-term transmission needs, transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, and transmission customers paying more than is necessary or appropriate to meet their transmission needs and/or forgoing benefits that outweigh their costs.[79]

47. The Commission determined that there is substantial evidence in the record to support the conclusion that the Commission's regional transmission planning and cost allocation requirements are deficient, thus rendering Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable. Specifically, the Commission found that existing regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[80]

48. As to the first deficiency—the lack of sufficiently long-term planning—the Commission cited evidence in the record demonstrating that, under the status quo, most

[79] *Id.*

[80] *Id.* P 114.

transmission planning regions do not plan beyond a 10-year transmission planning horizon.[81] The Commission stated that the absence of any consistent and sufficient longer-term assessment of transmission needs prevents transmission providers from identifying Long-Term Transmission Needs and considering regional transmission facilities that may be more efficient or cost-effective solutions to address those needs.[82] The Commission added that short-term transmission planning fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide and fails to create opportunities to "right size" the replacement of aging transmission facilities to address multiple transmission needs over the longer term. Further, the Commission stated that the time horizon over which much transmission planning is often occurring is shorter than the time needed to plan and construct large (e.g., high voltage or long distance) transmission facilities[83] and much too short to capture all of the benefits that regional transmission facilities can provide.[84]

49. The Commission noted that the likelihood that near-term assessments will fail to identify Long-Term Transmission Needs and more efficient or cost-effective regional transmission facilities to meet those needs is higher during periods of rapid change, as the

[81] *Id.* P 115.

[82] *Id.* (citations omitted).

[83] *Id.* P 116 (citations omitted).

[84] *Id.* (citations omitted).

electric sector is now experiencing, during which the need for transmission infrastructure is expected to grow considerably.[85]

50. The second deficiency the Commission discussed is that the Commission's existing regional transmission planning and cost allocation requirements fail to require transmission providers to account adequately on a forward-looking basis for known determinants of Long-Term Transmission Needs; moreover, the Commission stated, transmission providers are not consistently or sufficiently doing so.[86] The Commission further stated that the record demonstrates that there are numerous factors that increasingly shape Long-Term Transmission Needs, are known and identifiable, and have reasonably predictable effects, especially in the aggregate, such as reliability needs driven by the impact of extreme weather; trends in future generation additions and retirements; load growth; federal, federally-recognized Tribal, state, and local laws and regulations; and utility goals.[87] The Commission determined, however, that existing regional transmission planning processes frequently undervalue or do not consider some or all of these factors, and that the Commission's existing regional transmission planning requirements do not ensure that such factors will be sufficiently accounted for in that planning.[88] The Commission noted that the failure to adequately consider such factors

[85] *Id.* P 117 (citations omitted).

[86] *Id.* P 118.

[87] *Id.* P 119.

[88] *Id.* P 120.

delays planning for the transmission system's changing operational needs until shortly before those transmission needs manifest. As a result, the Commission stated, existing regional transmission planning processes are piecemeal and fail to take advantage of economies of scale in transmission investment or opportunities to address multiple transmission needs over multiple time horizons, which leads to transmission investment that is not more efficient or cost-effective and renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.[89]

51. The third deficiency that the Commission identified is that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The Commission pointed to evidence demonstrating that many regional transmission planning processes focus too narrowly only on some benefits, while other regional transmission planning processes fail entirely to consider cost savings associated with certain transmission facilities.[90] The Commission also explained that the cost-benefit analyses that transmission providers often use provide an inaccurate portrayal of the comparative benefits of different transmission facilities, which results in transmission customers forgoing benefits that may significantly outweigh their costs and in less efficient or cost-

[89] *Id.* P 121 (citations omitted).

[90] *Id.* P 122 & n.312.

effective transmission investments, and ultimately contributes to Commission-jurisdictional rates that are unjust and unreasonable.[91]

52. The Commission determined that, given its findings concerning the deficiencies in existing transmission planning requirements, and its conclusion that long-term, forward-looking, and more comprehensive regional transmission planning is needed, existing cost allocation requirements are also deficient and must be modified to properly account for Long-Term Regional Transmission Planning.[92]

53. The Commission determined that its current cost allocation requirements, which were designed in the context of the Order No. 1000 regional transmission planning process, are insufficient to appropriately allocate costs associated with regional transmission facilities selected in accordance with Order No. 1920's Long-Term Regional Transmission Planning requirements.[93] The Commission's existing Order No. 1000 cost allocation requirements contemplate the application of differing cost allocation methods to different types of transmission facilities, but Order No. 1920's approach to Long-Term Regional Transmission Planning accounts for multiple drivers of Long-Term Transmission Needs and results in Long-Term Regional Transmission Facilities that produce a broader set of benefits and therefore warrants a different approach to cost

[91] *Id.* P 123.

[92] *Id.* P 124.

[93] *Id.* P 126.

allocation.[94] The Commission also explained that existing Order No. 1000 regional transmission planning processes do not mandate the consideration of specific benefits and that information concerning these benefits may be relevant when allocating the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with their benefits.[95] Further, the Commission noted that under existing cost allocation requirements, there is no dedicated process to engage states in the development of regional cost allocation methods. The Commission explained that engaging states in cost allocation is particularly relevant to Long-Term Regional Transmission Planning given the long lead times for construction of transmission projects, which create uncertainty for Long-Term Regional Transmission Facilities and increase the importance of ensuring that such facilities will obtain needed siting approvals from the states and are thus timely and cost-effectively developed. The Commission therefore concluded that it is both necessary and appropriate to establish specific cost allocation requirements tailored to the Long-Term Regional Transmission Planning reforms.[96]

54. The Commission found that there is substantial evidence in the record demonstrating that Long-Term Regional Transmission Planning and cost allocation to

[94] *Id.*

[95] *Id.* (citing *ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639).

[96] *Id.*

identify and plan for Long-Term Transmission Needs does not occur on a consistent and sufficient basis.[97] The Commission added that this is largely due to the deficiencies it identified regarding existing regional transmission planning and cost allocation requirements.[98] The Commission also found that, under the status quo, transmission providers are meeting many transmission needs by identifying transmission solutions and developing transmission facilities outside of the regional transmission planning and cost allocation processes or in response to near-term reliability needs.[99] The Commission stated that this approach may not identify more efficient or cost-effective transmission solutions and will saddle consumers with the costs of relatively inefficient or less cost-effective piecemeal transmission investment and expansion.[100]

55. Moreover, the Commission found that transmission needs in most transmission planning regions are rapidly changing and exacerbating concerns arising from the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes and the corresponding failure by transmission providers to identify and evaluate more efficient or cost-effective transmission solutions to Long-Term Transmission Needs.[101] The Commission

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[97] *Id.* P 127 (citations omitted).

[98] *Id.*

[99] *Id.* (citations omitted).

[100] *Id.* P 128 (citations omitted).

[101] *Id.* P 129.

emphasized that it is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's jurisdiction or control, including, but not limited to, the increasing frequency of extreme weather events, customer preferences, demand growth, economic and technological trends, and federal, federally-recognized Tribal, state, and local policies.[102]

56. The Commission stated that Order No. 1920 does not aim to affect—either facilitate or hinder—any changes or decisions that occur outside of the Commission's jurisdiction.[103] Instead, the Commission explained, Order No. 1920 focuses on ensuring that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential; Order No. 1920 seeks to ensure that such regional transmission planning processes are adequately "*accounting for*" changes occurring outside of the Commission's jurisdiction, including the resource decisions that are the exclusive jurisdiction of states.[104]

57. The Commission disagreed with arguments that it could not rely on general findings, rather than individualized analyses of each, specific transmission planning

[102] *Id.* (citation omitted).

[103] *Id.* P 130 (emphasis in original).

[104] *Id.* (citing *PJM Power Providers Grp. v. FERC*, 88 F.4th 250, 275 (3d Cir. 2023); *Elec. Power Supply Ass'n v. Star*, 904 F.3d 518, 524 (7th Cir. 2018)).

region, as the basis for Order No. 1920.[105] The Commission explained that it was acting pursuant to relevant precedent, which makes clear that the Commission need not make findings that are region-specific in every case and is instead empowered to "rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution,"[106] notwithstanding regional variation among regional transmission planning processes. Moreover, the Commission acknowledged that, while transmission planning practices vary considerably between transmission planning regions, the record demonstrates that deficiencies in transmission planning processes "reach well beyond 'isolated pockets'"[107] and instead pervade large swathes of the country, including RTO/ISO and non-RTO/ISO planning regions.[108] Thus, the Commission added, Order No. 1920 does not present an "extreme 'disproportion of remedy to ailment.'"[109] The Commission also noted that it has discretion to decide the most efficient approach for resolving industry-wide problems.[110] Further, the Commission reasoned, "region-specific solutions will lead to 'siloed and disjunctive

[105] *Id.* P 132 (citations omitted).

[106] *Id.* (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (quoting *Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002))).

[107] *Id.* (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67) (alteration omitted).

[108] *Id.* (citations omitted).

[109] *Id.* (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67) (alteration omitted).

[110] *Id.* (citing Order No. 1000, 136 FERC ¶ 61,051 at P 60).

transmission planning policies [that] will not solve the problems facing the nation's electric grid.'"[111]

58. The Commission stated that the record shows that significant changes in transmission needs are well underway nationwide and that failing to account for Long-Term Transmission Needs threatens just and reasonable rates across the country.[112] The Commission also noted that significant investments in new transmission facilities are expected to occur and substantially affect Commission-jurisdictional rates that customers pay, which underscores the importance of addressing deficiencies in its regional transmission planning and cost allocation requirements now.[113]

### 3. Benefits of Long-Term Regional Transmission Planning and Cost Allocation to Identify and Plan for Long-Term Transmission Needs

59. Based on the record, the Commission found that Order No. 1920's requirements will help to ensure just and reasonable Commission-jurisdictional rates by addressing deficiencies in the existing regional transmission planning and cost allocation requirements and promoting enhanced reliability and more efficient or cost-effective transmission solutions.[114] The Commission noted evidence in the record demonstrating that the kind of regional transmission planning required by Order No. 1920 will help

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[111] *Id.* (quoting ACEG NOPR Reply Comments at 17).

[112] *Id.* P 133 (citation omitted).

[113] *Id.* (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 46, 50).

[114] *Id.* P 134.

transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to Long-Term Transmission Needs.[115]

60. The Commission found that Long-Term Regional Transmission Planning that expands the transmission planning horizon and considers factors affecting Long-Term Transmission Needs as well as a broader list of benefits will: (1) reduce reliance on transmission solutions that are relatively inefficient or less cost-effective because they address only short-term transmission needs; (2) unlock the benefits of economies of scale in transmission investment;[116] (3) enable opportunities to "right size" replacement transmission facilities;[117] (4) facilitate the selection of regional transmission facilities that could address multiple transmission needs over different time horizons; and (5) provide states, utilities, customers, and other stakeholders with greater insight and transparency into the costs and benefits of particular transmission solutions to address Long-Term Transmission Needs. The Commission concluded that these regional transmission planning and cost allocation reforms will help to ensure just and reasonable rates.[118] The Commission added that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes will also enhance reliability because a robust, well-planned transmission system is foundational to ensuring an

[115] *Id.* P 135.

[116] *Id.* P 136 (citation omitted).

[117] *Id.* (citations omitted).

[118] *Id.* (citations omitted).

affordable, reliable supply of electricity.[119] Additionally, the Commission cited evidence demonstrating how long-term, forward-looking, and more comprehensive regional transmission planning can better identify reliability needs and resolve those needs with more efficient or cost-effective transmission solutions.[120]

### B. The Commission Adequately Demonstrated that Existing Rates, or Practices Affecting Rates, Are Unjust and Unreasonable

61. We sustain the Commission's determination in Order No. 1920 that existing regional transmission planning and cost allocation processes are unjust and unreasonable, and unduly discriminatory or preferential. We conclude that this finding, as well as the Commission's finding that the identified deficiencies in transmission planning and cost allocation processes render existing Commission-jurisdictional rates unjust and unreasonable, was based on substantial record evidence, reflecting significant input from nearly 200 stakeholders across the country, third-party reports and studies, and the Commission's extensive knowledge of the industry and expert predictions regarding the transmission planning processes and cost allocation requirements that the Commission itself has established and oversees in carrying out its statutory responsibilities. We disagree with several rehearing parties who argue that the Commission failed to satisfy its burden under the first prong of FPA section 206 to show that Order No. 1000 regional transmission planning and cost allocation processes are unjust, unreasonable, or unduly

[119] *Id.* P 137.

[120] *Id.* P 138 (citations omitted).

discriminatory and preferential.[121] First, we disagree with certain rehearing parties as to the nature of the Commission's evidentiary burden under FPA section 206. Second, we conclude that the Commission's factual findings and the substantial evidence supporting those findings satisfies, and exceeds, the Commission's burden under FPA section 206. Third, we find that the "deficiencies identified by the Commission" in Order No. 1920 do not "'exist[] only in isolated pockets'" and such evidence is supported by the record. Finally, we conclude that the Commission has authority to conduct a nationwide rulemaking. We address these points in turn.

### 1. The Commission Correctly Characterized Its Statutory Burden

#### a. Requests for Rehearing

62. SERTP Sponsors contend that the Commission must demonstrate more than theoretical deficiencies to support nationwide policies and that systemic problems must be demonstrated beyond isolated issues.[122] SERTP Sponsors argue that Order No. 1920's findings, which are based on theory and supposition, are insufficient to carry the applicable burden and are contradicted by substantial specific evidence about SERTP.[123] SERTP Sponsors argue that *South Carolina Public Service Authority v. FERC* "does not

[121] Alabama Commission Rehearing Request at 3-4; Designated Retail Regulators Rehearing Request at 3, 7-8, 19-22; Industrial Customers Rehearing Request at 3-4, 6, 11-18; SERTP Sponsors Rehearing Request at 28-29, 31-37; Undersigned States Rehearing Request at 7, 19-21; Arizona Commission Rehearing Request at 19-20.

[122] SERTP Sponsors Rehearing Request at 34 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 71).

[123] *Id.*

stand for the proposition that any assertion of any theoretical problem by FERC is enough to satisfy the first step of the analysis under [s]ection 206."[124] SERTP Sponsors contend that except in limited circumstances—e.g., when there is a lack of empirical evidence—the D.C. Circuit requires more than theoretical deficiencies to support nationwide policies.[125]

63. Relatedly, Industrial Customers claim that Order No. 1920 is "legally infirm" because it does not make specific findings that rates and practices are unjust, unreasonable, or unduly discriminatory or preferential and instead "proposes to amend Order No. 1000 based upon mere concerns that Order No. 1000 *may not* be planning transmission in a manner that comports with the FPA."[126]

**b. Commission Determination**

64. We sustain our determination under the first prong of FPA section 206 and find that the Commission relied on sufficient and appropriate evidence to support its determination that existing rates are unjust and unreasonable. We disagree with SERTP Sponsors' and Industrial Customers' arguments that the Commission did not satisfy its section 206 burden because its analysis under the first prong of FPA section 206 was predicated "entirely on theory and supposition"[127] or on "mere concerns" that Order No.

[124] *Id.* at 31 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65).

[125] *Id.* at 29, 31, 34.

[126] Industrial Customers Rehearing Request at 16-17 (emphasis in original).

[127] SERTP Sponsors Rehearing Request at 31.

1000 processes "*may not* be planning transmission in a manner that comports with the FPA."[128] Setting aside that in making this determination the Commission did not rely solely on "supposition" or "mere concerns" about deficiencies in the Order No. 1000 regional transmission planning and cost allocation processes,[129] SERTP Sponsors' and Industrial Customers' arguments disregard well-established principles regarding the findings and type of evidence sufficient to support a conclusion that the Commission's burden under the first prong of FPA section 206 has been satisfied, as established by longstanding authority, including the D.C. Circuit's opinion in *South Carolina Public Service Authority v. FERC*.

65. In *South Carolina Public Service Authority v. FERC*, the D.C. Circuit—reviewing Order No. 1000, which the Commission adopted to address the "theoretical threat" of unjust or unreasonable rates "stemm[ing] from the absence of [transmission] planning processes that take a sufficiently broad view of both the tasks involved and the means of addressing them"—rejected arguments similar to those made here by Industrial Customers.[130] In particular, petitioners there, similar to Industrial Customers here, argued

[128] Industrial Customers Rehearing Request at 16-17.

[129] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at PP 93-97, 114-123 (discussed below in The Commission Adequately Supported Its Determination on Step One of Section 206 section).

[130] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64 (alteration omitted) (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 52).

that the "'theoretical threat' described by the Commission fail[ed] to satisfy its evidentiary burden under [s]ection 206 . . . ."[131]

66. The court squarely rejected that contention.[132] It explained that the substantial evidence required to support a finding that an existing practice affecting rates is "unjust, unreasonable, unduly discriminatory or preferential" pursuant to FPA section 206 "requires 'more than a scintilla' but 'less than a preponderance' of evidence."[133] Substantial evidence, however, "does not necessarily mean empirical evidence,"[134] and, in satisfying the substantial evidence standard, the Commission may rely on its own predictions as long as they are "'at least likely enough to be within the Commission's authority' and [are] based on reasonable economic propositions."[135] As the court

[131] *Id.*

[132] *Id.*

[133] *Id.* at 54 (quoting *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 645 (D.C. Cir. 2010)), 64-65 (citing 16 U.S.C. 824e(a)), 5 U.S.C. 706(2)(E))).

[134] *Id.* at 65 (citing 5 U.S.C. 706(2)(E)); *see also Xcel Energy Servs. Inc. v. FERC*, 41 F.4th 548, 560-61 (D.C. Cir. 2022) ("In making decisions, it is 'perfectly legitimate for the Commission to base its findings on basic economic theory,' including relying on 'generic factual predictions,' as long as the agency 'explains and applies the relevant economic principles in a reasonable manner.'" (cleaned up) (quoting *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 531 (D.C. Cir. 2010) (per curiam))); *id.* ("Where the 'promulgation of generic rate criteria clearly involves the determination of policy goals or objectives, and the selection of means to achieve them,' the 'courts reviewing an agency's selection of means are not entitled to insist on empirical data for every proposition on which the selection depends.'" (alterations omitted) (quoting *Associated Gas Distribs. v. FERC*, 824 F.2d 981, 1008 (D.C. Cir. 1987) (*Associated Gas Distributors*))).

[135] *Id.*; *see also id.* at 76 ("[A]t least in circumstances where it would be difficult or even impossible to marshal empirical evidence, the Commission is free to act based

recognized, "[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall."[136]

67. The court in reviewing Order No. 1000 determined that the Commission had satisfied its evidentiary burden under section 206. In particular, the Commission had identified "significant changes in the nation's electric power industry" that presented "significant challenges to the development and cost allocation of interstate transmission projects" and highlighted five deficiencies in Order No. 890's transmission planning and cost allocation processes.[137] Ultimately, the court held that the Commission's determination that the then-current transmission planning and cost allocation practices were unjust or unreasonable was based on substantial evidence.[138]

68. By insisting that the Commission was required to demonstrate that rates or practices are, *in fact*, unjust, unreasonable, or unduly discriminatory or preferential,[139] SERTP Sponsors and Industrial Customers overlook principles articulated in *South*

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upon reasonable predictions rooted in basic economic principles.").

[136] *Id.* at 65 (quoting *Associated Gas Distributors*, 824 F.2d at 1008); *see also Cent. Hudson Gas & Elec. Corp. v. FERC*, 783 F.3d 92, 109 (2d Cir. 2015) ("FERC may permissibly rely on economic theory alone to support its conclusions so long as it has applied the relevant economic principles in a reasonable manner and adequately explained its reasoning.").

[137] *Id.* at 66.

[138] *See id.*at 67.

[139] Industrial Customers Rehearing Request at 16-17; SERTP Sponsors Rehearing Request at 34.

*Carolina Public Service Authority v. FERC*, including that the Commission need not provide empirical evidence for every proposition and may instead rely upon the threat of unjust and unreasonable rates as a basis for taking action.[140] Their argument is predicated on a faulty premise that, in a rulemaking setting, the Commission must wait for a threat to result in actual harm, and may not act where it anticipates harmful consequences.[141] But in *South Carolina Public Service Authority v. FERC*, the court explicitly reached the opposite conclusion, holding that the Commission satisfied its evidentiary burden under section 206 by relying on the theoretical threat to just and reasonable rates even though the Commission acknowledged other evidence in the record.[142] SERTP Sponsors are thus incorrect to suggest that the *South Carolina Public Service Authority v. FERC* court allowed the Commission to rely on generic factual findings only because the record lacked empirical evidence.[143]

69. *South Carolina Public Service Authority v. FERC* makes clear that, because "substantial evidence" is not limited to empirical evidence and may include generic factual predictions, the Commission could have satisfied its evidentiary burden under the

[140] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64-65; *see also id.* at 85 ("[W]hether a threat of unjust or unreasonable rates derives from a practice or the absence thereof, Section 206 empowers the Commission to address it."); *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 844 (D.C. Cir. 2006) (stating that the Commission could choose to "rely solely on a theoretical threat").

[141] *See* Industrial Customers Rehearing Request at 16-17.

[142] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64, 67.

[143] SERTP Sponsors Rehearing Request at 29.

first prong of FPA section 206 with analysis based on theoretical threats and predictions regarding such threats based on reasonable economic propositions within the Commission's expertise.[144] Here, however, the Commission established a theoretical threat and, as discussed below, also cited substantial empirical and other record evidence to support its finding that the existing regional transmission planning processes and cost allocation requirements—and the rates that have resulted from them—are unjust and unreasonable.

### 2. The Commission Adequately Supported Its Determination on Step One of Section 206

#### a. Requests for Rehearing

70. Designated Retail Regulators argue that, in its analysis under the first prong of section 206 of the FPA, the Commission made conclusory, "blanket claims that are unsupported by evidence."[145] Undersigned States similarly assert that the Commission does not "point to evidence in the record sufficient to support" a finding that existing regional transmission planning and cost allocation processes are resulting in unjust, unreasonable, unduly discriminatory, and preferential Commission-jurisdictional rates because "such evidence does not exist."[146] Arizona Commission contends that the evidence in the record used to support Order No. 1920's section 206 finding consists

[144] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65 (quoting *Associated Gas Distributors*, 824 F.2d at 1008).

[145] Designated Retail Regulators Rehearing Request at 20-21.

[146] Undersigned States Rehearing Request at 21.

largely of comments from special interest groups that will profit from Order No. 1920 and not evidence specific to the Arizona Commission.[147]

71. Industrial Customers claim that, rather than making specific findings that existing practices are unjust and unreasonable, the Commission made "several generic assertions . . . to reach very broad conclusions,"[148] and "generically assert[ed]" that the Commission satisfies its burden under the first prong of the FPA section 206 inquiry "based on the record."[149] Industrial Customers assert that the failure to reach specific findings, supported by substantial evidence, under the first prong of FPA section 206 renders Order No. 1920 legally infirm.[150] Industrial Customers claim that the absence of detailed and substantiated findings makes it "difficult, if not impossible" for transmission providers to file compliance filings because it will be challenging to develop and propose solutions without an understanding of the root problem the Commission is trying to fix.[151]

**b. Commission Determination**

72. We continue to find that the Commission made adequate findings under the first prong of FPA section 206 and marshalled substantial evidence to support those findings. We are therefore not persuaded by rehearing parties' arguments to the contrary. Below,

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[147] Arizona Commission Rehearing Request at 19.

[148] Industrial Customers Rehearing Request at 16.

[149] *Id.* at 13 (alteration omitted).

[150] *Id.* at 17.

[151] *Id.* at 17-18.

we first summarize the empirical and other record evidence the Commission cited to support its findings that Commission-jurisdictional regional transmission planning and cost allocation processes are unjust and unreasonable because they result in transmission providers failing to identify Long-Term Transmission Needs, to evaluate and select more efficient or cost-effective transmission solutions to meet those transmission needs, and to allocate the costs of transmission facilities selected to meet those transmission needs in a manner that is at least roughly commensurate with benefits.[152] Next, we summarize the Commission's generic factual predictions. We conclude that this evidence is more than sufficient to meet the Commission's evidentiary burden under section 206.

73. Based on the robust record before it, the Commission concluded that transmission investment, which has increased nationwide since the Commission issued Order No. 1000,[153] is likely to grow substantially in coming years due to three factors that are driving a growing need for new transmission infrastructure.[154] First, reports and

[152] Order No. 1920, 187 FERC ¶ 61,068 at PP 114-122.

[153] *Id.* P 92 (referencing a study by the US DOE, which found that annual investment in transmission first exceeded $5 billion per year in 2006, doubled to more than $10 billion per year by 2010, doubled again by 2016, and has been between $18 billion and $22 billion annually since 2014 (quoting US DOE, *National Electric Transmission Congestion Study*, at 9-10 (Sept. 2020), https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf)); *id.* (citing estimates from The Brattle Group and Grid Strategies that transmission developers in the United States invested $20 to $25 billion annually in transmission facilities from 2013 to 2020 (citing Brattle-Grid Strategies Oct. 2021 Report at 2); Brattle Apr. 2019 Competition Report at 2-3 & fig.1)).

[154] *Id.* P 93 (citing a number of studies projecting sustained transmission spending through at least 2050, including one by Princeton University projecting that high voltage transmission capacity must expand by 60 percent by 2030 at a capital cost of $330 billion

comments in the record demonstrated that longer-term reliability needs are changing as transmission providers increasingly rely on regional transmission facilities to ensure operational stability as extreme weather events become more frequent and variable resources increasingly enter the resource mix.[155] Based on evidence in the record, the Commission concluded that transmission investment is likely to be more critical, and produce more reliability benefits for customers, as extreme weather and other system contingencies become more frequent.[156] Second, the Commission noted evidence that

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and must triple by 2050 at a capital cost of $2.2 trillion, as well as another by The Brattle Group projecting $750 billion of new transmission investment between 2023 and 2050. (citing Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 108 (Oct. 2021), https://netzeroamerica.princeton.edu/the-report; Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy*, at iii (2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf)).

[155] The Commission cited comments and reports demonstrating that transmission infrastructure can be critical to system reliability during extreme weather events such as Winter Storm Uri. *Id.* P 94 & n.209 (citing ACEG NOPR Initial Comments at 22 n.63 (stating that during Winter Storm Uri, "[a]n additional 1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion and kept power flowing to hundreds of thousands of Texans."); Grid Strategies July 2021 Extreme Weather Report at 7-8 ("The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during [Winter Storm Uri]. . . . In contrast to the 13,000 MW MISO was importing during the peak of [the] event, ERCOT was only able to import about 800 MW of power throughout the event.")). The Commission also cited research from US DOE's Lawrence Berkeley National Laboratory suggesting that 50% of the value created by alleviating transmission system congestion occurs during only 5% of the hours during which the transmission system is used, further evidence of the significant value of transmission during unanticipated events. *Id.*P 94 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[156] *Id.* P 94 (citing LBNL Aug. 2022 Transmission Value Study at 33; Clean Energy Associations NOPR Initial Comments at 5).

electric demand is projected to increase significantly in the coming decades due to electrification trends and new large loads associated with evolving industrial and commercial needs.[157] Again, relying on record evidence, the Commission found that these increases in aggregate electricity demand will have significant consequences for the transmission system.[158] Third, the Commission found that the resource mix is changing due to federal, federally-recognized Tribal, state, and local policies,[159] customer demands

[157] *Id.* P 95 (citing Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy* (Mar. 2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf); John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over*, at 3 (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf ("Over [2023], grid planners nearly doubled the 5-year load growth forecast. The nationwide forecast of electricity demand shot up from 2.6% to 4.7% growth over the next five years, as reflected in 2023 FERC [Form 714] filings. Grid planners forecast peak demand growth of 38 gigawatts (GW) through 2028."); N. Amer. Elec. Reliability Corp., *2023 Long-Term Reliability Assessment*, at 33 (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf ("Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022* [*Long-Term Reliability Assessment*], reversing a decades-long trend of falling or flat growth rates.")).

[158] *See id.* P 95 (citing National Grid NOPR Initial Comments at 6 (discussing preliminary findings of the ISO-NE 2050 Transmission Study, which show "significant new transmission will be needed to reliably serve" increased future loads assumed in the study (citing ISO-NE, 2050 Transmission Study (2023), https://www.iso-ne.com/static-assets/documents/2023/08/2050_study_ma_cetwg_2023_aug_final.pdf))).

[159] *Id.* P 96 & nn.223-227 (noting numerous jurisdictions that have adopted decarbonization, electrification, and renewable energy-related laws and policies); *id.* (citing ACORE NOPR Initial Comments at 1-2 & n.2; American Clean Power Ass'n, *It's a Big Deal for Job Growth and for a Clean Energy Future* (2022),

for clean energy,[160] utility emission commitments,[161] and the changing economics of resources that comprise the resource mix.[162]

74. Considering the changing transmission investment landscape, the Commission then relied on substantial record evidence to find that the Commission's existing regional transmission planning and cost allocation requirements are deficient in three ways and therefore fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis.[163]

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https://cleanpower.org/blog/its-a-big-deal-for-job-growth-and-for-a-clean-energy-future ("Analysis suggests that the [Inflation Reduction Act] could more than triple clean energy production in the U.S. and lead to $600 billion in capital investment in clean energy infrastructure."); Evergreen Action NOPR Initial Comments at 3-4; NextEra NOPR Reply Comments at 5); *id.* P 99.

[160] *Id.* P 97 ("Since 2014, for example, 'commercial and industrial customers have contracted for more than 52 GW of clean energy.'" (alteration omitted) (quoting Advanced Energy Buyers NOPR Initial Comments at 5)).

[161] *Id.* P 97 & nn.233-37 (noting that Exelon, Dominion, AEP, Southern, Entergy, Duke Energy, NextEra, and Tennessee Valley Authority have all announced some version of a net-zero carbon emission plan or commitment).

[162] *Id.* P 97 & n.239 (citing ACORE ANOPR NOPR Initial Comments at app. 1, p. 22 ("Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.")); Order No. 1920, 187 FERC ¶ 61,068 at P 99 ("[A]s of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources[,] . . . [and] those trends are projected to continue, with over 1,300 GW of wind, solar, and storage resources in interconnection queues across the country as of 2021." (citing SREA NOPR Initial Comments at 1-2; AEE NOPR Initial Comments at 12-13; California Commission NOPR Initial Comments at 65; Renewable Northwest NOPR Initial Comments at 36; FERC, State of the Markets 2020, at 10, 12 (Mar. 2021); FERC, State of the Markets 2023, at 4 (Mar. 2024); US DOE Initial Comments at app. B, PP. 8-9, 26).

[163] *Id.* P 112.

75. The first deficiency that the Commission identified is the lack of a sufficiently long-term assessment of transmission needs.[164] The Commission explained that most transmission planning regions do not plan beyond a 10-year transmission planning horizon,[165] which is shorter than the time needed to plan and construct large (e.g., high voltage or long distance) transmission facilities[166] or to capture all of the benefits that regional transmission facilities can provide.[167] According to comments and studies in the

[164] Order No. 1920, 187 FERC ¶ 61,068 at P 115 (citing MISO ANOPR Reply Comments at 5 ("[G]iven long-term needs of an evolving system, additional transmission is necessary to reliably serve customers now and into the future. These challenges require immediate action and further delay only increases the risk that system enhancements may not be in place in the timeframe needed."); PIOs NOPR Initial Comments at 13 ("[A] short-term outlook under-forecasts longer-term transmission needs, preventing the development of more cost-effective transmission facilities, and fails to consider how the needs of the transmission system are shifting."); US DOE ANOPR Initial Comments at 10 (stating that failure to plan transmission far enough ahead results in "adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals")).

[165] *Id.* (noting that commenters point out that ISO-NE, SERTP, and NorthernGrid use a 10-year transmission planning horizon, while PJM uses a 5-year transmission planning horizon for what it refers to as its short-term transmission planning process and a 6-to-15-year transmission planning horizon for what it refers to as its intermediate-term transmission planning process).

[166] *Id.* P 116 (citing AEP NOPR Initial Comments at 11; Nevada Commission NOPR Initial Comments at 7 n.24; PIOs NOPR Initial Comments at 14; Renewable Northwest NOPR Initial Comments at 5; SEIA NOPR Initial Comments at 6). The Commission discussed MISO's MVP initiative, which took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, a 10-year period that does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval. Order No. 1920, 187 FERC ¶ 61,068 at P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio*, at 39 (2021)).

[167] *Id.* (citing SEIA NOPR Initial Comments at 6; US DOE NOPR Initial

record, short-term transmission planning also fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide and does not create opportunities to "right size" the replacement of aging transmission facilities.[168] Based on this evidence, the Commission concluded that relying solely on shorter-term transmission planning and studies fails to identify Long-Term Transmission Needs and consequently undervalues or entirely ignores the benefits of transmission investments to meet those needs.[169]

76. The second deficiency that the Commission identified is that transmission providers are not required to account adequately on a forward-looking basis for known

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Comments at 33).

[168] *Id.* (citing ACORE NOPR Initial Comments at 4 ("The narrowly focused current approaches [to transmission planning] do not identify opportunities to take advantage of the large economies of scale in transmission that come from 'up-sizing' reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals." (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)); PIOs ANOPR Initial Comments at 10-11; SEIA ANOPR Initial Comments at 14).

[169] *Id.* P 117 & n.290 ("Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers' expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution." (quoting US DOE ANOPR Initial Comments at 10)); *id.* ("While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward." (quoting Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report*, at 6 (July 28, 2022), https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf)).

determinants of Long-Term Transmission Needs or to account for such known determinants in a manner that ensures the identification and evaluation of more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.[170] The Commission highlighted concrete evidence of this deficiency, including that some regional transmission planning processes ignore factors relevant to identifying transmission needs,[171] while others fail to account for factors that will shape future load.[172] The Commission added that, while forecasting necessarily involves uncertainty, the record demonstrates that there are numerous factors that increasingly shape Long-Term Transmission Needs, that are known and identifiable, and have reasonably predictable effects, especially in the aggregate.[173] These include, for example, reliability needs driven by the impact of extreme weather,[174] trends in future generation additions

[170] *Id.* P 118.

[171] *Id.* (discussing record evidence that some existing regional transmission planning processes ignore trends in future generation, the impact of extreme weather, state laws, and utility goals) (citing Acadia Center and CLF NOPR Initial Comments at 1; GridLab NOPR Initial Comments at 4-5; Brattle-Grid Strategies Oct. 2021 Report at 36; Grid Strategies July 2021 Extreme Weather Report at 5; SPP Market Monitor ANOPR Initial Comments at 3 & n.5; Renewable Northwest NOPR Initial Comments at 4, 8, 12; SREA NOPR Initial Comments at 25)).

[172] *Id.* (discussing record evidence that existing regional transmission planning processes fail to account for factors shaping electrification trends like electric vehicles and data centers (citing AEE ANOPR Initial Comments at 18; Clean Energy Buyers NOPR Initial Comments at 7-8; National Grid NOPR Initial Comments at 8; AEE ANOPR Initial Comments at 18; Rocky Mountain Institute NOPR Supplemental Comments at 1; WIRES NOPR Supplemental Comments at attach. 1, p. 36)).

[173] *Id.* P 119.

[174] *Id.* P 120 (citing ACEG NOPR Initial Comments at 63; NERC NOPR Initial

and retirements,[175] load growth,[176] federal, federally-recognized Tribal, state, and local laws and regulations,[177] and utility goals.[178] The Commission explained, however, that existing regional transmission planning processes frequently undervalue or do not consider some or all of these factors, and the Commission's existing regional transmission planning requirements do not ensure otherwise.[179] The Commission found that the failure to adequately consider such factors delays planning for the transmission

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Comments at 6; Evergreen Action NOPR Initial Comments at 2 ("[A]dditional transmission built under improved planning procedures would [] create large reliability benefits. With increasing extreme weather events due to climate change—including wildfires, winter storms, hurricanes, and more—additional transmission infrastructure and grid improvements are increasingly necessary for resilience purposes."); WE ACT NOPR Initial Comments at 2).

[175] *Id.* P 120 (citing Pattern Energy NOPR Initial Comments at 26; SEIA NOPR Initial Comments at 9).

[176] *Id.* (citing Northwest and Intermountain NOPR Initial Comments at 5 n.12; John Wilson and Zach Zimmerman, *The Era of Flat Demand is Over,* Grid Strategies, at 3, 6 (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/ 2023/12/National-Load-Growth-Report-2023.pdf (noting the 5-year load growth forecast has nearly doubled from 2.6% to 4.7% and "transmission investments need to increase just to keep up with demand")).

[177] *Id.* PP 119, 120 (citing Acadia Center and CLF NOPR Initial Comments at 8; AEE NOPR Initial Comments at 10 (noting that "[a]s of September 2020, 38 states and the District of Columbia had adopted renewable portfolio standards, and 21 states (plus the District of Columbia and Puerto Rico) – representing more than half of the U.S. population – include a target of 100% renewable energy by 2050 or sooner. Many of these requirements have been enacted in statute and are binding on utilities and retail energy providers.")).

[178] *Id.* P 120 (citing Renewable Northwest NOPR Initial Comments at 6; SREA NOPR Initial Comments at 41-46).

[179] *Id.*

system's changing operational needs until shortly before those transmission needs manifest, resulting in transmission planning processes that are piecemeal and fail to take advantage of economies of scale in transmission investment or opportunities to address multiple transmission needs over multiple time horizons.[180]

77. The Commission explained that the third deficiency is that transmission providers are not required to adequately consider the broader set of benefits that accrue to regional transmission facilities planned to meet Long-Term Transmission Needs.[181] Relying on record evidence, the Commission found that many current regional transmission planning and cost allocation processes consider only a narrow subset of benefits that regional transmission facilities provide[182] or fail entirely to consider cost savings associated with certain transmission facilities.[183]

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[180] *Id.* P 121 (PIOs NOPR Initial Comments at 10-11; Renewable Northwest NOPR Initial Comments at 8).

[181] *Id.* P 122 (citation omitted).

[182] *Id.* (citing Brattle-Grid Strategies Oct. 2021 Report at 2 ("[M]ost of [the nation's recent transmission] investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits."); Massachusetts Attorney General ANOPR Initial Comments at 22; PIOs NOPR Initial Comments at 10-11).

[183] *Id.* (citing SREA NOPR Initial Comments at 24 ("SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the 'Economic Planning Studies' only evaluate the costs of potential upgrades to the system, but none of the benefits.")).

78. These deficiencies have concrete consequences that illustrate the deleterious effects of inadequate regional transmission planning processes. For instance, the Commission cited evidence showing that investment in regional transmission facilities has declined in some regions as compared to the investment that was occurring prior to Order No. 1000 and that, across all non-RTO/ISO regions, not a single transmission facility has been selected since implementation of Order No. 1000.[184] Further, the Commission noted that within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process occur, much of that investment has been in transmission projects that only address immediate reliability needs.[185]

79. At the same time, the Commission found, significant expansion of the transmission system is occurring through one-off, piecemeal, interconnection-related

[184] *Id.* P 101 (citing Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, Planning for the Future: *FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 25 & fi. 8 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf; ACORE ANOPR Initial Comments at 4 ("Despite the potential benefits, regional transmission investment has not increased and in some regions even has declined over the past decade.") (citation omitted); State Agencies NOPR Initial Comments at 23 ("Regionally planned projects have [] declined in RTOs/ISOs . . . ." (citing John C. Gravan & Rob Gramlich, NRRI Insights, *A New State-Federal Cooperation Agenda for Regional and Interregional Transmission*, at 2 (Sept. 2021), https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685); FERC, Staff Report, *2017 Transmission Metrics*, at 19 (Oct. 6, 2017), https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf).

[185] *Id.* P 101 (citing Southwestern Power Group NOPR Initial Comments at 15; PIOs ANOPR Initial Comments at 93 & n.276; Ari Peskoe, *Is the Utility Syndicate Forever?*, 42 Energy L.J. 1, 56-57 (2021)).

network upgrades constructed in response to individual generator interconnection requests.[186] The Commission noted the shortcomings of relying on the generator interconnection process for addressing transmission needs, including that the generator interconnection process does not look at time horizons beyond the specific interconnection request(s) being studied, comprehensively assess any transmission needs beyond those created by the specific interconnection request(s), or achieve the economies of scale in transmission investment that long-term, forward-looking, and more comprehensive regional transmission planning processes can provide.[187]

80. The Commission also cited evidence that, since the issuance of Order No. 1000, the majority of investment in transmission facilities has been in local transmission facilities, a trend that is accelerating across multiple regions.[188] The Commission pointed out that in RTO/ISO regions one half of the nearly $70 billion in aggregate transmission investments by Commission-jurisdictional transmission providers between 2013 and 2017 was approved outside of regional transmission planning processes.[189]

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[186] *Id.* P 104 (citing Pine Gate NOPR Initial Comments at 6, 8-10; PIOs NOPR Initial Comments at 9).

[187] *Id.* P 106 (citing Anbaric NOPR Initial Comments at 5; Clean Energy Associations NOPR Initial Comments at 15; Exelon NOPR Initial Comments at 5; Pine Gate NOPR Initial Comments at 9; PIOs NOPR Initial Comments at 10; SEIA NOPR Initial Comments at 2; Southeast PIOs NOPR Initial Comments at 37).

[188] *Id.* P 109 (citing NOPR, 179 FERC ¶ 61,028 at PP 39-40 (2022)).

[189] *Id.* (citing PIOs NOPR Initial Comments at 9).

81. Relying on the foregoing record of empirical and other record evidence, the Commission found that existing regional transmission planning requirements are deficient and fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis.[190] Substantial facts in the record also supported the Commission's finding that the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs,[191] a trend that reflects that existing regional transmission planning requirements are leading to relatively inefficient or less cost-effective results.

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[190] *Id.* P 127 (citing New Jersey Commission NOPR Initial Comments at 8 (explaining that, outside of limited circumstances, PJM, Florida, ISO-NE, Southeastern Regional, South Carolina Regional, WestConnect, NorthernGrid, NYISO, SPP, and CAISO do not conduct multi-driver or portfolio transmission planning, which has required ratepayers to pay for tens of billions of dollars in unnecessary transmission projects); NextEra ANOPR Initial Comments at 71 ("While there are examples of longer-term planning currently being utilized by some regions, such as MISO's annual 15-year Futures assessment or SPP's 20-year Integrated Transmission Plan run every five years, there is no standard as to what time horizon long-term planning must study, nor how often this planning should be done. Further, no standards or guidelines exist as to what should be included in such long-term planning to ensure that customers are charged just and reasonable rates for the most efficient and cost-effective investments given the most comprehensive and up-to-date information available."); Western PIOs NOPR Initial Comments at 4-28 (arguing that in the Western United States transmission planning outside of CAISO is not developed and is ineffective); Brattle-Grid Strategies Oct. 2021 Report at 13-15 & tbl. 2 (documenting inconsistent "use of proactive, scenario-based, multi-value processes" across various planning authorities, including NYISO, CAISO, MISO, PJM, ISO-NE, Florida, Southeast Regional, and South Carolina")).

[191] *Id.* PP 127-128 (citing LS Power NOPR Initial Comments at 46-50; PIOs NOPR Initial Comments at 9-10 (explaining that about half of the approximately $70 billion in aggregate transmission investment by Commission-jurisdictional transmission owners in RTO/ISO regions was approved outside of regional transmission planning

82. Moreover, as courts have made clear, the Commission was also entitled to base its findings regarding the need for reform on generic factual predictions.[192] In *Associated Gas Distributors*, the court explained that the Commission is permitted to act on predictions that are unsupported by record evidence when such predictions are "at least likely enough to be within the Commission's authority" and based on reasonable behavioral or economic assumptions.[193] Indeed, "[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall."[194] Thus, in *South Carolina Public Service Authority v. FERC*, the court held that the Commission satisfied its burden on the first prong of FPA section 206 analysis where "[t]he threat to just and reasonable rates arose, *in the Commission's judgment*, from existing planning and cost allocation practices that could thwart the identification of more efficient and cost-effective transmission solutions."[195]

83. Here, relying on its expertise and knowledge of the industry, the Commission made several predictions that were fully consistent with the grounds for action that courts

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processes)).

[192] *See Citadel FNGE Ltd. v. FERC*, 77 F.4th 842, 858 (D.C. Cir. 2023); *Xcel Energy Servs. Inc. v. FERC*, 41 F.4th at 560-61; *Associated Gas Distributors*, 824 F.2d at 1008.

[193] *Associated Gas Distributors*, 824 F.2d at 1008 (discussing *Wis. Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985); *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511 (D.C. Cir. 1984)).

[194] *Associated Gas Distributors*, 824 F.2d at 1008.

[195] *S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d at 66 (emphasis added).

have accepted in the past, including in *Associated Gas Distributors* and *South Carolina Public Service Authority v. FERC*. First, the Commission made such predictions when it explained how observed deficiencies in existing regional transmission planning and cost allocation requirements are resulting in deleterious consequences and ultimately rendering rates unjust and unreasonable.[196] Next, the Commission predicted that existing cost allocation requirements—which were designed and established in the context of existing shorter-term Order No. 1000 regional transmission planning processes and lack a dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods—are insufficient to appropriately allocate costs associated in the context of the Long-Term Regional Transmission Planning requirements established in Order No. 1920.[197] Finally, the Commission anticipated that, absent Order No. 1920's reforms, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development.[198] Such predictions are precisely the type of evidence that courts have permitted the Commission to use as the basis for section 206 rulemaking.

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[196] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 117, 121, 123.

[197] *Id.* P 126.

[198] *Id.* P 113.

84. Given both the empirical and other record evidence and the generic factual predictions on which the Commission relied, we are unpersuaded by Designated Retail Regulators' and Undersigned States' arguments[199] that the Commission's determination under the first prong of FPA section 206 was unsupported by substantial evidence. Indeed, the Commission's findings regarding ongoing changes to the nation's electric power industry and deficiencies in existing transmission planning and cost allocation processes, along with the evidence supporting those findings, are similar to, or the same as, the type of findings and evidence that formed the basis for action in Order No. 1000 and that the *South Carolina Public Service Authority v. FERC* court determined satisfied the Commission's burden under the first prong of FPA section 206.[200]

85. For these same reasons, we disagree with Arizona Commission's unsubstantiated contention that the evidence in the record on which the Commission relied to satisfy its section 206 burden consists largely of comments from special interest groups that will profit from the final rule.[201] The Commission's findings were based on an extensive record consisting of over 30,000 pages of comments from nearly 200 stakeholders, including industry participants such as transmission providers,[202] generation

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[199] Designated Retail Regulators Rehearing Request at 20-21; Undersigned States Rehearing Request at 21.

[200] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65-67; *see also* Order No. 1000, 136 FERC ¶ 61,051 at PP 44-47, 78-83.

[201] *See* Arizona Commission Rehearing Request at 19.

[202] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 115 (citing PJM NOPR Initial Comments; MISO ANOPR Reply Comments; ITC NOPR Initial Comments); *id*.

developers,[203] trade associations,[204] customer groups,[205] and governmental entities.[206] The Commission's findings also relied upon many reports and studies in the record and the Commission's expert predictions.[207] Arizona Commission disregards this substantial evidence.

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P 116 (citing AEP NOPR Initial Comments); *id.* P 118 (citing National Grid NOPR Initial Comments); *id.* P 136 (citing Exelon NOPR Initial Comments.

[203] *See, e.g.*, *id.* P 120 (citing Pattern Energy NOPR Initial Comments); *id.* P 127 (citing NextEra ANOPR Initial Comments; LS Power NOPR Initial Comments).

[204] *See, e.g.*, *id.* P 116 (citing SEIA ANOPR Initial Comments); *id.* P 137 (citing EEI NOPR Initial Comments).

[205] *See, e.g.*, *id.* P 118 (citing Clean Energy Buyers NOPR Initial Comments; ELCON NOPR Initial Comments); *id.* PP 119-120 (citing Industrial Customers NOPR Initial Comments).

[206] *See, e.g.*, *id.* P 115 (citing Massachusetts Attorney General NOPR Initial Comments; US DOE ANOPR Initial Comments); *id.* P 116 (citing Nevada Commission NOPR Initial Comments); *id.* P 120 (citing NERC NOPR Initial Comments); *id.* PP 121, 127, 135 (citing New Jersey Commission NOPR Initial Comments); *id.* P 128 (citing Michigan State Entities NOPR Initial Comments).

[207] *See, e.g.*, *id.* P 92 (citing US DOE, *National Electric Transmission Congestion Study*, (Sept. 2020), https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf); Brattle-Grid Strategies Oct. 2021 Report); *id.* P 101 (citing ACEG Jan. 2021 Planning Report; John C. Gravan & Rob Gramlich, NRRI Insights, A New State-Federal Cooperation Agenda for Regional and Interregional Transmission (Sept. 2021), https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685); FERC, Staff Report, *2017 Transmission Metrics* (Oct. 6, 2017), https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf)); *id.* P 102 (citing Midcontinent Indep. Sys. Operator, *RGOS: Regional Generation Outlet Study* (Nov. 2020)); MTEP2017 Review); *id.* P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio* (2021); Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report* (July 28, 2022), https://cdn.misoenergy.org/MTEP21%20Addendum-

86. We are also unpersuaded by Industrial Customers' assertion that the absence of substantial evidence makes it "difficult if not impossible" for transmission providers to submit compliance filings because it will be challenging to develop and propose solutions without an understanding of the root problem that the Commission is trying to fix.[208] As discussed above, the Commission made detailed findings addressing the deficiencies of existing transmission planning and cost allocation requirements and the processes related to those requirements.[209] Moreover, in developing their compliance filings, transmission providers will rely on the Commission's specific identification of the new requirements established under the second prong of FPA section 206, not on the deficiencies in existing transmission planning and cost allocation processes and requirements identified under the first prong of the Commission's section 206 analysis. We are therefore not

LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf); *id.* P 118 (citing Grid Strategies July 2021 Extreme Weather Report; Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms* (July 2022), https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf; Rob Gramlich, et al., *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)); *id.* P 120 (citing BPA, *TSR Study and Expansion Process* (Dec. 7, 2021), https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf; John Wilson and Zach Zimmerman, *The Era of Flat Demand is Over*, Grid Strategies (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/ 2023/12/National-Load-Growth-Report-2023.pdf).

[208] Industrial Customers Rehearing Request at 17.

[209] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

persuaded that Order No. 1920's findings lack the requisite specificity to enable transmission providers to make compliance filings.

### 3. The Commission Identified Deficiencies that Exist beyond Isolated Pockets

#### a. Requests for Rehearing

87. Alabama Commission and SERTP Sponsors assert that Order No. 1920's generalized observations criticizing the effectiveness of existing transmission planning processes are based on examples from other parts of the country and do not apply to, or address evidence regarding, Alabama and the Southeast.[210] According to Alabama Commission, Alabama and SERTP already achieve many, if not most, of the goals of the final rule.[211] Alabama Commission contends that Alabama has a resource planning process that accounts for needed transmission buildout to maintain reliable service and proactively plans its transmission system to maintain deliveries from existing resources and accommodate generation additions.[212] Alabama Commission adds that the SERTP process ensures that there are no regional transmission solutions that are more efficient and cost-effective than the solutions identified through the underlying state-jurisdictional process.[213]

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[210] Alabama Commission Rehearing Request at 3; SERTP Sponsors Rehearing Request at 28-29, 31.

[211] Alabama Commission Rehearing Request at 3.

[212] *Id.* at 3-4.

[213] *Id.* at 4.

88. SERTP Sponsors allege that the SERTP process has been highly efficient, and that its integrated resource plan and request for proposal-driven transmission planning and other similar processes effectively address the Commission's concerns regarding siloed planning, lack of scenario planning, and local versus regional project focus. SERTP Sponsors argue that, while the court in *South Carolina Public Service Authority v. FERC* allowed the Commission to support a rulemaking by finding a systemic problem not limited to isolated pockets, given SERTP's scale, scope, and that it does not suffer from the theoretical deficiencies identified in Order No. 1920, the Commission has not satisfied the standard set out in *South Carolina Public Service Authority v. FERC.*[214] SERTP Sponsors claim that they ensure a comprehensive and proactive approach to transmission system development by incorporating various factors into their planning, including reliability, economic growth, environmental attributes, and public policy requirements.[215] According to SERTP Sponsors, the alternative projects identified through its regional transmission planning analyses have not proved to be more efficient or cost-effective than those identified through SERTP's integrated resource plan and request for proposal-driven transmission planning.[216]

89. SERTP Sponsors also disagree with Order No. 1920's finding that nationwide transmission grid expansion is primarily driven through the generator interconnection

[214] SERTP Sponsors Rehearing Request at 34 n.100.

[215] *Id.* at 32.

[216] *Id.* at 33.

process, because in the Southeast, transmission expansion is driven by the underlying integrated resource plan/request for proposal and other similar planning processes.[217] SERTP Sponsors state that Southern Companies added $5.3 billion in transmission capital expenditures from 2017-2021, with only $57 million (just over 1%) related to generation interconnection.[218] Similarly, SERTP Sponsors explain that Duke Energy added an estimated $503 million of transmission facilities to its transmission plan, targeted at unlocking areas of its transmission system that were repeatedly identified in past generator interconnection studies as constrained to more timely and cost-effectively integrate needed generation resources.[219] SERTP Sponsors contend that Order No. 1920 ignored this evidence.[220]

90. Designated Retail Regulators and Undersigned States aver that, contrary to the Commission's claims, the evidence in the record demonstrates that a substantial portion of transmission providers have been and are engaging in long-term planning.[221] For example, Designated Retail Regulators and Undersigned States point to MISO's Multi-Value Projects (MVP) process, which they claim includes most of the requirements of

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[217] *Id.* at 36.

[218] *Id.* at 36-37.

[219] *Id.* at 37 (citing Duke NOPR Initial Comments at 8-9).

[220] *Id.* (citing *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983) (*State Farm*) (internal citation omitted)).

[221] Designated Retail Regulators Rehearing Request at 21-22; Undersigned States Rehearing Request at 22-23.

Order No. 1920.[222] Designated Retail Regulators and Undersigned States also contend that CAISO, NYISO, Southern Companies, and other transmission planners also have sufficient long-term planning and that SPP indicated in its NOPR comments that its OATT requires planning processes that are sufficient to meet the intent and desired outcomes of Order No. 1920.[223]

**b. Commission Determination**

91. We disagree with rehearing parties who argue that the Commission did not satisfy its burden under the first prong of FPA section 206 because certain transmission providers may already engage in some form of long-term transmission planning.[224] We are satisfied that the Commission identified deficiencies in existing regional transmission planning and cost allocation processes that exist beyond isolated pockets.

92. First, "[t]hat some commenters may engage in sufficient transmission planning processes 'is as unastonishing as it is irrelevant,'" where, as here, the deficiencies identified by the Commission and supported by substantial evidence reach well beyond

[222] Designated Retail Regulators Rehearing Request at 21-22; Undersigned States Rehearing Request at 22.

[223] Designated Retail Regulators Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65-66); SPP NOPR Initial Comments at 3); Undersigned States Rehearing Request at 22-23 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65-66); SPP NOPR Initial Comments at 3).

[224] Alabama Commission at 3-4; Designated Retail Regulators Rehearing Request at 21-22; Undersigned States Rehearing Request at 22-23; SERTP Sponsors Rehearing Request at 28-37.

"isolated pockets."[225] Record evidence demonstrates that transmission planning regions across the country—including ISO-NE, SERTP, and NorthernGrid—do not plan beyond a 10-year transmission planning horizon,[226] which is problematic for several reasons, including that regional transmission facilities often have lead times that exceed 10 years[227] and that a 10-year transmission planning horizon is much too short to capture all of the benefits that regional transmission facilities can provide.[228] Further, comments and reports in the record establish that transmission planning processes in several regions do not account for known determinants of Long-Term Transmission Needs such as trends in future generation[229] and extreme weather.[230] The record demonstrates that many regional

[225] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (first quoting *Wis. Gas Co. v. FERC*, 770 F.2d at 1157; and then quoting *Associated Gas Distributors*, 824 F.2d at 1019).

[226] Order No. 1920, 187 FERC ¶ 61,068 at P 115 & n.282 (citing ITC NOPR Initial Comments at 9 (referring to the "broad use of a 10-year planning horizon in the existing transmission planning processes of many major planning regions")).

[227] *Id.* P 116 (citing AEP NOPR Initial Comments at 11; Nevada Commission NOPR Initial Comments at 7 n.24; PIOs NOPR Initial Comments at 14; Renewable Northwest NOPR Initial Comments at 5; SEIA NOPR Initial Comments at 6). The Commission discussed MISO's MVP initiative, which took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, a 10-year period that does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval. Order No. 1920, 187 FERC ¶ 61,068 at P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio*, at 39 (2021)).

[228] *Id.* (citing SEIA NOPR Initial Comments at 6; US DOE NOPR Initial Comments at 33).

[229] *Id.* P 118 & n.294.

[230] *Id.* P 118 & n.293.

transmission planning processes also fail to adequately consider the range of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[231] And the Commission cited evidence showing that, except in limited cases, transmission providers in many regions do not conduct multi-driver or portfolio transmission planning, which has led to ratepayers paying for relatively inefficient or less cost-effective transmission projects.[232]

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[231] *Id.* P 122 & nn.309-12 (citing Massachusetts Attorney General ANOPR Initial Comments at 22 ("New England's siloed approach to transmission planning inhibits identification of multi-value solutions."); PIOs Initial Comments at 10 ("[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs . . . . [M]ultiple quantifiable benefits to transmission . . . are being ignored in the transmission planning process."); SREA Initial Comments at 24 ("SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the 'Economic Planning Studies' only evaluate the costs of potential upgrades to the system, but none of the benefits.").

[232] *Id.* P 127 & n.318 (citing New Jersey Commission NOPR Initial Comments at 8 (explaining that, outside of limited circumstances, PJM, Florida, ISO-NE, Southeastern Regional, South Carolina Regional, WestConnect, NorthernGrid, NYISO, SPP, and CAISO do not conduct multi-driver or portfolio transmission planning, which has required ratepayers to pay for tens of billions of dollars in unnecessary transmission projects); NextEra ANOPR Initial Comments at 71 ("While there are examples of longer-term planning currently being utilized by some regions, such as MISO's annual 15-year Futures assessment or SPP's 20-year Integrated Transmission Plan run every five years, there is no standard as to what time horizon long-term planning must study, nor how often this planning should be done. Further, no standards or guidelines exist as to what should be included in such long-term planning to ensure that customers are charged just and reasonable rates for the most efficient and cost-effective investments given the most comprehensive and up-to-date information available."); Western PIOs NOPR Initial Comments at 4-28 (arguing that in the Western United States transmission planning outside of CAISO is not developed and is ineffective); Brattle-Grid Strategies Oct. 2021 Report at 13-15 & tbl. 2 (documenting inconsistent "use of proactive, scenario-based, multi-value processes" across various planning authorities, including NYISO, CAISO,

93. We are unpersuaded by SERTP Sponsors' argument that the Commission failed to satisfy its burden under the first prong of FPA section 206 analysis because it ignored evidence that transmission expansion in SERTP is driven by "planning processes that proactively anticipate[] a changing resource mix and the use of firm 'physical' transmission service—and not by interconnection requests."[233] As Order No. 1920 makes clear, the deficiencies of existing transmission planning and cost allocation processes result in various detrimental outcomes reflecting that existing requirements are unjust and unreasonable. Over-reliance on generator interconnection requests to expand the transmission system is just one such example. The Commission noted other existing deficiencies as well, including that the majority of investments in transmission facilities are occurring through local transmission planning processes and in-kind replacements, which focus on the needs of individual transmission provider footprints and miss the potential for more efficient or cost-effective regional transmission facilities.[234]

94. Moreover, although SERTP Sponsors assert that SERTP "does not suffer from [Order No. 1920's] theoretical deficiencies,"[235] and Alabama Commission asserts that that the Commission ignored evidence that transmission planning in SERTP "achieves

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MISO, PJM, ISO-NE, Florida, Southeast Regional, and South Carolina")).

[233] SERTP Sponsors Rehearing Request at 36.

[234] Order No. 1920, 187 FERC ¶ 61,068 at P 109-111.

[235] SERTP Sponsors Rehearing Request at 34 & n.100.

many, if not most, of the goals in the Final Rule,"[236] the Commission, in fact, cited evidence that SERTP's transmission planning process suffers from each of the three deficiencies that the Commission identified in Order No. 1920. Record evidence demonstrates that SERTP's regional transmission planning and cost allocation process (1) does not perform a sufficiently long-term assessment of transmission needs;[237] (2) does not adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs;[238] and (3) fails to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[239]

95. Further, Designated Retail Regulators and Undersigned States provide no support for their claim that "a substantial portion of transmission providers" are currently conducting "effective long-term planning."[240] Instead, they assert that CAISO, NYISO,

[236] Alabama Commission Rehearing Request at 3.

[237] Order No. 1920, 187 FERC ¶ 61,068 at P 115 (noting that SERTP uses a 10-year transmission planning horizon (citing Southeast PIOs NOPR Initial Comments at 12)).

[238] *Id.* P 118 n.294 (explaining that in 2021, SERTP stated that because it did not receive any proposals for transmission needs driven by Public Policy Requirements for the 2021 planning cycle, it identified no possible transmission needs driven by Public Policy Requirements for further evaluation of potential transmission solutions in that planning cycle (citing SREA NOPR Initial Comment at 25)).

[239] *Id.* P 122 n.312 ("SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the 'Economic Planning Studies' only evaluate the costs of potential upgrades to the system, but none of the benefits." (quoting SREA NOPR Initial Comments at 24)).

[240] *See* Designated Retail Regulators Rehearing Request at 21; Undersigned States

Southern Companies, and "[o]ther regions . . . have sufficient long-term planning"[241] without explaining how the transmission planning processes in those regions do not suffer from the deficiencies that the Commission identified in Order No. 1920 as necessitating reform of its existing regional transmission planning and cost allocation requirements. Similarly, Designated Retail Regulators' and Undersigned States' conclusion that SPP's transmission planning processes are "sufficient to meet the Commission's desired outcomes"[242] cites to a single sentence in comments SPP filed nearly two years before the Commission adopted Order No. 1920, in which SPP stated only that it "believe[d] its current study processes and initiatives [to be] sufficient to meet the Commission's desired outcomes."[243] Such unsupported statements about the sufficiency of transmission planning processes in various transmission planning regions similarly fail to establish that those transmission providers' existing transmission planning and cost allocation processes do not suffer the deficiencies that the Commission identified in Order No. 1920. While MISO's regional transmission planning process may

Rehearing Request at 22.

[241] Designated Retail Regulators Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65-66)); Undersigned States Rehearing Request at 23 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65-66)).

[242] Designated Retail Regulators Rehearing Request at 22 (citing SPP NOPR Initial Comments at 3); Undersigned States Rehearing Request at 22 (citing SPP NOPR Initial Comments at 3).

[243] SPP NOPR Initial Comments at 3.

satisfy certain of Order No. 1920's requirements, this does not establish that deficiencies in existing regional transmission planning and cost allocation processes are occurring only in "isolated pockets."

96. Moreover, SERTP Sponsors do not identify any authority supporting the contention that the Commission cannot make a generic finding under section 206 unless it shows that every transmission provider's OATT is unjust and unreasonable or unduly discriminatory or preferential. Nor are we convinced by SERTP Sponsors' attempts to distinguish *South Carolina Public Service Authority v. FERC*, where the court held that "the Commission may act by generic rule . . . without first finding that the rates charged by individual utilities are unjust or unlawful when it concludes that any tariff violating the rule would have such adverse effects on the interstate gas or energy market as to render it unjust and unreasonable."[244] SERTP Sponsors assert that, given "SERTP's scale and scope and the fact that it does not suffer from [Order No. 1920's] theoretical deficiencies," the reasoning of *South Carolina Public Service Authority v. FERC* is inapplicable here. However, while we do not need to make specific findings regarding individual transmission providers, we note, as discussed above, that record evidence demonstrates that SERTP does suffer from each of the theoretical deficiencies that the Commission identified in Order No. 1920. Significantly, in finding that existing regional transmission planning and cost allocation requirements are not just and reasonable, the

[244] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 86 (quoting *Associated Gas Distributors*, 824 F.2d at 1008).

Commission also recognized that "the present is not a prediction of the future"[245] in light of the threat, documented by substantial evidence, that, absent Order No. 1920's reforms, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development. That "the present is not a prediction of the future" is especially true in a period of rapid change like the electric sector is now experiencing. Given industry trends that the Commission highlighted in Order No. 1920—changing longer-term reliability needs due to more frequent extreme weather events and the increasing share of variable resources entering the resource mix,[246] significantly increasing demand,[247] and changes to the nation's resource mix[248]—even if the identified deficiencies in existing regional transmission planning and cost allocation requirements have yet to manifest clearly in every transmission planning region, we can

[245] *Id.* at 67 (quoting Order No. 1000-A, 139 FERC ¶ 61,132 at P 65); *see also* Order No. 1000-A, 139 FERC ¶ 61,132 at P 65 ("The Commission is authorized to make rules with prospective effect that will prevent situations that are inconsistent with the FPA from occurring, which means that it is authorized to consider how the future may be different from the present if the rules it proposes are not adopted.").

[246] Order No. 1920, 187 FERC ¶ 61,068 at P 94.

[247] *Id.* P 95.

[248] *Id.* P 96.

reasonably predict that they will in the near future. The Commission acted within its authority to prevent that eventuality from materializing.[249]

97. Moreover, the Commission found that the existing regional transmission planning and cost allocation *requirements* are unjust and unreasonable under of the first prong of FPA section 206.[250] While transmission planning regions vary in their specific approaches, and some transmission providers, within their discretion, may have adopted practices that satisfy some of Order No. 1920's requirements, there is no guarantee that these practices will continue in the absence of Order No. 1920's requirements. If transmission providers believe that they already satisfy any of the requirements of Order No. 1920, they may seek to demonstrate that they do so in their compliance filings.

#### 4. The Commission Has the Authority to Conduct a Generic Rulemaking

##### a. Requests for Rehearing

98. Undersigned States argue that the Commission lacks authority to make rate determinations on a generic, national level.[251] Undersigned States note that under section

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[249] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64-65, 85 ("[W]hether a threat of unjust or unreasonable rates derives from a practice or the absence thereof, Section 206 empowers the Commission to address it.").

[250] Order No. 1920, 187 FERC ¶ 61,068 at P 114 ("Based on the record, including the comments submitted in response to the NOPR, we find that there is substantial evidence to support the conclusion that *deficiencies in the Commission's existing regional transmission planning and cost allocation requirements* are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential.") (emphasis added)).

[251] Undersigned States Rehearing Request at 23.

206, the Commission has the power to determine, after a hearing held upon its own motion or upon complaint, that the rates charged by a specific utility subject to Commission jurisdiction are unjust, unreasonable, unduly discriminatory, or preferential, and if so, to adjust that rate.[252] Undersigned States claim that this does not authorize the Commission to issue Order No. 1920.[253]

99. Arizona Commission argues that there is no evidence that it has acted in a discriminatory or unfair way while creating rates and processes.[254] Therefore, Arizona Commission argues, Order No. 1920's section 206 finding is unlawful when applied to the Arizona Commission because there must be an individual finding as to the Arizona Commission before section 206 can be applied to it. Arizona Commission states that it is arbitrary and capricious "to infer any evidence in the record supports the conclusion the [Arizona Commission] has acted in a discriminatory or unfair way."[255]

**b. Commission Determination**

100. We continue to find that the Commission has the authority to institute the reforms adopted in Order No. 1920 and that it was not required to demonstrate that transmission planning and cost allocation processes are unjust, unreasonable, or unduly discriminatory or preferential with respect to specific transmission providers. Rehearing parties'

[252] *Id.* at 23-24 (citing 16 U.S.C. 824e).

[253] *Id.* at 24.

[254] Arizona Commission Rehearing Request at 19.

[255] *Id.* at 19-20.

arguments to the contrary seem to rely on a misinterpretation of FPA section 206. Section 206 delegates substantial responsibility to the Commission:

101. Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.[256]

102. As the Commission explained in Order No. 1920, and as courts have confirmed, transmission planning and cost allocation processes are "are practices affecting rates subject to the Commission's exclusive jurisdiction."[257] Rehearing parties cite no precedent suggesting that section 206 requires the Commission to act on an individual, utility-by-utility basis, and we are aware of none.

103. Contrary to Undersigned States' argument that the Commission lacks authority to make rate determinations on a generic, national level, courts have consistently interpreted section 206 to allow the Commission to regulate on a national level, through notice-and-

[256] 16 U.S.C. 824e.

[257] Order No. 1920, 187 FERC ¶ 61,068 at P 86 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55).

comment rulemakings, when the Commission finds systemic issues throughout the industry that cause practices affecting rates charged by public utilities to be unjust, unreasonable, or unduly discriminatory or preferential.[258] Nearly 40 years of precedent has consistently interpreted the Commission's FPA section 206 authority—and the corresponding, nearly identical authority in the Natural Gas Act[259]—as providing the Commission with the authority to "rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution."[260] In fact, in interpreting the nearly identical provision of the Natural Gas Act, the D.C. Circuit stated that "[t]he Commission is not required to make individual findings, however, if it exercises its Natural Gas Act § 5 authority by means of a generic rule."[261] The Commission has, time and time again, exercised section 206 authority through generic rulemakings that rely on industry-wide findings rather than region-by-region or utility-specific findings.[262]

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[258] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (upholding Order No. 1000); *TAPS*, 225 F.3d 667, *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (upholding Order No. 888).

[259] 15 U.S.C. 717d(a).

[260] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (quoting *Interstate Nat. Gas of Am. v. FERC*, 285 F.3d at 37; *see also TAPS*, 225 F.3d at 687-88; *Associated Gas Distributors*, 824 F.2d 981; *Wis. Gas Co. v. FERC*, 770 F.2d at 1166 & n.36.

[261] *Associated Gas Distributors*, 824 F.2d at 1008. It is "well settled that comparable provisions of the Natural Gas Act and [FPA] are to be construed *in pari materia*." *Ky. Utils. Co. v. FERC*, 760 F.2d 1321, 1325 n.6 (D.C. Cir. 1985).

[262] *See, e.g.*, *TAPS*, 225 F.3d 667 (upholding Order No. 888, which was promulgated under FPA section 206 and premised on general systemic conditions rather than evidence regarding individual utilities); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (same for Order No. 1000); *Elec. Storage Participation in Mkts. Operated by Reg'l*

Indeed, Order No. 1920 itself builds upon existing transmission planning and cost allocation requirements adopted by the Commission through other generally applicable, nationwide rulemakings. Thus, the Commission was not required to make specific findings as to the Arizona Commission or transmission planning and cost allocation processes within Arizona or any given state. Moreover, Order No. 1920's reforms are directed to transmission providers, consistent with the Commission's jurisdiction,[263] and do not require any action by state regulatory authorities.[264] In light of the Commission's authority to act on a generic basis to reform the practices of all transmission providers, the Commission reasonably exercised its broad discretion to proceed by nationwide rulemaking to remedy the deficiencies that it determined in Order No. 1920 render its existing regional transmission planning and cost allocation requirements unjust and unreasonable.[265]

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*Transmission Organs. and Indep. Sys. Operators*, Order No. 841, 83 FR 9580 (Mar. 6, 2018), 162 FERC ¶ 61,127, at P 21 (2018), *order on reh'g*, Order No. 841-A, 167 FERC ¶ 61,154 (2019), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 964 F.3d 1177 (D.C. Cir 2020) (*NARUC*); Order No. 890, 118 FERC ¶ 61,119 at PP 41-43.

[263] Order No. 1920, 187 FERC ¶ 61,068 at PP 1 n.2, 253.

[264] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 263 ("[T]his final rule directly regulates transmission planning and cost allocation processes, . . . directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201.").

[265] *See Wis. Gas Co. v. FERC*, 770 F.2d at 1157 ("An administrative agency must be equipped to act either by general rule or individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity. The choice made between proceeding by general rule or by individual, *ad hoc* litigation is one that lies primarily in the informed discretion of the administrative agency." (alterations omitted)

### C. The Commission Demonstrated that the Replacement Rate is Just and Reasonable

#### 1. Requests for Rehearing

104. Several rehearing parties argue that the Commission did not demonstrate that the replacement tariff and transmission planning requirements are just and reasonable.[266] According to Designated Retail Regulators, Order No. 1920 "requires the construction of transmission to socialize the costs of policies of some States and parties over others and shifts the costs caused by interconnecting remotely located generators to everyone," but provides "no analysis showing that the resulting rates are just and reasonable."[267] Industrial Customers contend that Order No. 1920 generically asserts, without "evidence, proof, or data," that its reforms "*should* provide cost savings."[268]

105. Designated Retail Regulators also claim that Order No. 1920 contradicts Order Nos. 888 and 890, under which the cost of transmission is generally borne by load. Designated Retail Regulators argue that, in contrast, the final rule promotes the construction of long-haul transmission designed to move energy from remote resources located in one state to load located in another without any contractual or other assurance to the load-serving entity that the remotely located resource will provide firm energy.

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(quoting *SEC v. Chenery Corp*., 332 U.S. 194, 202-03 (1947)).

[266] Designated Retail Regulators Rehearing Request at 22-23; Undersigned States Rehearing Request at 23.

[267] Designated Retail Regulators Rehearing Request at 22-23; *see also* Undersigned States Rehearing Request at 23 (similar).

[268] Industrial Customers Rehearing Request at 20.

Designated Retail Regulators contend that, in the absence of a contractual or regulatory requirement to supply firm energy, there is no reasonable rationale that would justify allocating the cost for this transmission to remotely located load.[269] Designated Retail Regulators also argue that remotely located customers who are required to pay for transmission facilities without regulatory or contractual guarantees of receiving firm energy are not beneficiaries, must less cost causers.[270]

106. Industrial Customers argue that Order No. 1920 is arbitrary and capricious and does not reflect reasoned decision-making because it fails to consider and address costs to consumers, which is an essential element of the problem of transmission planning and cost allocation.[271] Arizona Commission echoes this argument and contends that Order No. 1920 fails to protect consumers and will saddle ratepayers with trillions of dollars in increased rates in coming years, resulting in unfair rates.[272] Arizona Commission adds that the "several factors" that Order No. 1920 requires transmission providers to "consider[ ] in transmission planning and cost allocation" should have included fairness,

[269] Designated Retail Regulators Rehearing Request at 23.

[270] *Id.* at 23-24.

[271] Industrial Customers Rehearing Request at 19-20 (citing *State Farm*, 463 U.S. at 43).

[272] Arizona Commission Rehearing Request at 20.

reasonableness of cost, or consideration of who caused the cost, as mandated by the FPA.[273]

### 2. Commission Determination

107. We continue to find that the replacement regional transmission planning and cost allocation requirements that the Commission adopted in Order No. 1920 are just and reasonable.[274] We disagree with rehearing parties' arguments that the Commission did not demonstrate that the replacement rate is just and reasonable, as it appears that these arguments may mischaracterize Order No. 1920. Designated Retail Regulators argue that Order No. 1920 "requires the construction of transmission to socialize the costs of the policies of some States and parties over others and shifts the costs caused by interconnecting remotely located generators to everyone."[275] Like Order No. 1000, Order No. 1920's "transmission planning reforms are concerned with process, and are not intended to dictate substantive outcomes."[276] Order No. 1920 specifically provided that "[t]he regional transmission planning requirements and cost allocation requirements in

[273] *Id.* at 21.

[274] Order No. 1920, 187 FERC ¶ 61,068 at PP 134-138.

[275] Designated Retail Regulators Rehearing Request at 22-23; *see also* Undersigned States Rehearing Requests at 23 (similar).

[276] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 58 (quoting Order No. 1000-A, 139 FERC ¶ 61,132 at P 188); *see infra* Statutory Authority section.

this final rule, like those of Order Nos. 890 and 1000, are focused on the transmission planning *process*, and do not require any substantive outcomes from this process."[277]

108. Moreover, Order No. 1920 did not change the Commission's cost causation requirements and does not contradict Order Nos. 888 and 890, under which the cost of transmission is generally borne by load.[278] Order No. 1920 reiterated that "any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent."[279] Order No. 1920 further stated that "[n]othing in this final rule requires states to subsidize other states' public policies and, indeed, this final rule requires, consistent with long-established Commission and court precedent, that transmission customers within a transmission planning region need only pay costs that are 'roughly commensurate' with the benefits that transmission providers estimate they will receive from a regional transmission facility."[280] Thus, "even if one state's public policy is a driver of a Long-

[277] Order No. 1920, 187 FERC ¶ 61,068 at P 232.

[278] *See infra* Federal/State Division of Authority section.

[279] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F. 3d at 87; Order No 1000, 136 FERC ¶ 61,051 at P 10; *ICC v. FERC I*, 576 F.3d at 476); *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 1297 ("Any cost allocation method(s) that transmission providers propose . . . must allocate costs in a manner that is at least roughly commensurate with estimated benefits . . . .").

[280] *Id.* P 267 (citing *Ill. Com. Comm'n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (*ICC v. FERC III*); *ICC v. FERC I*, 576 F.3d at 477; *Sw. Power Pool, Inc.*, 182 FERC ¶ 61,141, at P 12 (2023)); *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 280 ("[T]he final rule categorically does not require states to subsidize other states' public policies or

Term Transmission Need, the costs of a Long-Term Regional Transmission Facility that transmission providers select will be allocated to transmission customers only to the extent that they benefit from that facility and only to a degree that is at least roughly commensurate with the benefits that facility provides to them."[281] For these reasons, we also disagree with Designated Retail Regulators' argument that Order No. 1920 contradicts Order Nos. 888 and 890. Nonetheless, we believe certain clarifications discussed further below will alleviate Designated Retail Regulators' and Undersigned States' concerns regarding Order No. 1920's impact on multi-state cost allocation.[282]

109. We are similarly unpersuaded by Designated Retail Regulators' assertion that the Commission failed to satisfy its burden under the second prong of FPA section 206 because, under Order No. 1920, "there is no reasonable rationale that would justify . . . remotely located customers being required to pay for transmission facilities without regulatory or contractual guarantees of receiving firm energy."[283] The physics of an interconnected electric transmission system are such that even customers distant from new Long-Term Regional Transmission Facilities and without specific contractual

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generation decisions," but instead, "consistent with the cost causation principle, [the] final rule requires customers to pay for a share of the costs of new Long-Term Regional Transmission Facilities only to the extent that *they* benefit from those facilities and, even then, any share they pay must be roughly commensurate with the benefits they receive.").

[281] *Id.* P 282.

[282] *See supra* Concerns Regarding Cost Causation section.

[283] Designated Retail Regulators Rehearing Request at 23-24.

arrangements with such facilities *may* benefit from those facilities.[284] And any proposed cost allocation method for Long-Term Regional Transmission Facilities *must* allocate the costs of a new Long-Term Regional Transmission Facility in a manner at least roughly commensurate with the estimated benefits of the facility.[285] Beyond arguing that Order No. 1920 contradicts Order Nos. 888 and 890, Designated Retail Regulators do not argue that the Commission lacks authority to mandate the allocation of costs where there is no contractual or regulatory requirement to supply firm energy, and we do not believe that such a limitation exists.[286]

110. Additionally, the Commission found that Order No. 1920's requirements—that transmission providers conduct Long-Term Regional Transmission Planning that will ensure the identification, evaluation, and selection, as well as the allocation of costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs—will address the deficiencies in the existing regional transmission planning and cost allocation requirements. Furthermore, the Commission determined,

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[284] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 85 ("Entities that contract for service on the transmission grid cannot choose to affect only the transmission facilities for which they have entered into a contract and cannot claim that they are not using or benefiting from such transmission facilities simply because they did not enter a contract to use them." (quoting Order No. 1000-A, 139 FERC ¶ 61,132 at P 561 (cleaned up)).

[285] Order No. 1920, 187 FERC ¶ 61,068 at P 1305.

[286] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 84 (reasoning that the text of section 206 does not limit "cost allocation to entities with preexisting commercial relationships," and instead "empowers the Commission to fix 'any rate' 'demanded, observed, charged, or collected by any public utility for any transmission . . . subject to the jurisdiction of the Commission,' and 'any . . . practice' 'affecting such rate.'").

these requirements will promote enhanced reliability and more efficient or cost-effective transmission solutions, which will help to ensure just and reasonable rates.[287] The Commission's finding was based on consideration of the record and reasonable economic predictions, which indicate that long-term, forward-looking, and more comprehensive regional transmission planning that identifies Long-Term Transmission Needs helps transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to meet those needs.[288] These points are especially true considering the clarifications we adopt below.

111. For instance, the Commission was persuaded by empirical evidence demonstrating the success of MISO's Long-Range Transmission Plan in delivering more efficient or cost-effective transmission solutions.[289] By addressing public policy, economic, and reliability transmission planning needs simultaneously through its MVP category, MISO eliminated the need for $300 million in future baseline reliability upgrades and provided production cost savings that exceeded the entire cost of the portfolio by $10 billion.[290]

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[287] Order No. 1920, 187 FERC ¶ 61,068 at P 134.

[288] *Id.* PP 135-138 (citing ACEG NOPR Initial Comments 53-56; Brattle-Grid Strategies Oct. 2021 Report at 7 & nn.13-14; Clean Energy Associations NOPR Initial Comments at 25-27; Exelon NOPR Initial Comments 5; ITC NOPR Initial Comments at 44; MISO NOPR Initial Comments at 88; MTEP2017 Review at 6, 8; New Jersey Commission NOPR Initial Comments at 4; PIOs NOPR Initial Comments at 10, 35; SEIA NOPR Initial Comments 25-26).

[289] *Id.* P 135.

[290] *Id.* (MTEP2017 Review at 6).

The Commission noted that the cost savings that MISO experienced were the direct product of more comprehensive, longer-term regional transmission planning.[291]

112. The Commission also made several reasonable economic predictions regarding the effects of Order No. 1920. It was, for instance, reasonable for the Commission to predict that the transmission planning reforms adopted in Order No. 1920, which bear many similarities to MISO's MVP process, will have similar results and that longer-term regional transmission planning that considers a wider array of relevant factors will yield a more efficient or cost-effective selection of regional transmission facilities to meet Long-Term Transmission Needs, thus saving customers money.[292] The Commission reasonably concluded, and we continue to find, that forgoing this type of planning and requiring customers to bear the costs of relatively inefficient and less cost-effective transmission development results in unjust and unreasonable Commission-jurisdictional rates.[293]

113. We understand concerns raised by Arizona Commission and Industrial Customers that Order No. 1920 fails to protect consumers and will impose substantial costs on ratepayers.[294] However, in Order No. 1920, the Commission found that the *existing*

[291] *Id.* P 136.

[292] *See id.*

[293] *Id.* P 112.

[294] *See* Arizona Commission Rehearing Request at 20-21; Industrial Customers Rehearing Request at 19-20.

approach to regional transmission planning is resulting in customers paying more than necessary or appropriate to meet their transmission needs, forgoing benefits that outweigh their costs, or some combination thereof.[295] Thus, the Commission adopted reforms in Order No. 1920 that are necessary to ensure that regional transmission planning processes identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, so that customers do not continue to pay for relatively inefficient or less cost-effective transmission development.[296] Addressing costs to ratepayers was central to the reforms that the Commission adopted in Order No. 1920, and the Commission cited evidence that more comprehensive, longer-term regional transmission planning results in significant cost saving for customers.[297] Further, we disagree with Industrial Customers' argument that Order No. 1920 states, without "evidence, proof, or data," that its reforms "*should* provide cost savings."[298] As discussed above, the Commission cited robust and diverse evidence to support its finding that the type of regional transmission planning required by the final rule will likely result

[295] Order No. 1920, 187 FERC ¶ 61,068 at P 117.

[296] *Id.* P 113; *see also id.* P 136 ("[R]egional transmission planning and cost allocation reforms [adopted in Order No. 1920] will benefit customers by leading to more efficient or cost-effective transmission investment, thereby helping to ensure just and reasonable rates." (citations omitted)).

[297] *E.g.*, *Id.* P 135 (citing MTEP2017 Review at 6).

[298] Industrial Customers Rehearing Request at 20 (emphasis in original).

in cost savings to customers relative to the status quo approach.[299] Nonetheless, we believe the clarifications adopted herein will alleviate Industrial Customers' concerns.

114. We also recognize Arizona Commission's argument that the "several factors" that Order No. 1920 requires transmission providers to "consider[ ] in transmission planning and cost allocation" should have included fairness or reasonableness of cost or consideration of who caused the cost.[300] We believe these factors are appropriately accounted for in other stages of the regional transmission planning and cost allocation process. For example, the evaluation process considers reasonableness of costs by considering cost estimates for, as well as the benefits of, identified Long-Term Regional Transmission Facilities.[301] The cost allocation process also considers fairness and cost causation, as "transmission customers within a transmission planning region need only pay costs that are 'roughly commensurate' with the benefits that transmission providers estimate they will receive from a regional transmission facility."[302] However, we believe certain clarifications adopted herein will address the concerns underlying Arizona Commission's argument.

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[299] *See supra* The Commission Adequately Supported Its Determination on Step One of Section 206 section; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 135 & n.346 (citing a projection that proactive, portfolio-based transmission planning in PJM could ultimately save ratepayers over $30 billion compared to the status quo).

[300] Arizona Commission Rehearing Request at 21.

[301] Order No. 1920, 187 FERC ¶ 61,068 at PP 955, 958.

[302] *Id.* P 267; *see BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268-69 (D.C. Cir. 2014) ("[T]he cost causation principle itself manifests a kind of equity.").

### D. The Commission's Section 206 Findings Were Not Circular

#### 1. Requests for Rehearing

115. Industrial Customers and SERTP Sponsors argue that the Commission's findings under the two prongs of section 206 are circular.[303] According to Industrial Customers, rather than cite specific record evidence or specify the problems that the Commission seeks to address, the Commission relies on the benefits of Order No. 1920's remedy—e.g., longer-term, more comprehensive regional transmission planning—to support its threshold finding under the first prong of FPA section 206.[304] Industrial Customers thus assert that Order No. 1920 relies on "circular reasoning," whereby the Commission develops a desired solution and then finds that the current absence of that desired solution renders the status quo unjust and unreasonable.[305] This approach, Industrial Customers contend, does not reflect reasoned decision making.[306] Further, Industrial Customers argue that proceeding in this fashion exceeds the Commission's authority under the FPA and could allow the Commission to "essentially legislate to achieve any desired outcome."[307] Industrial Customers assert that the D.C. Circuit has previously determined that the Commission failed to meet its section 206 burden and therefore committed error

[303] Industrial Customers Rehearing Request at 13-15; SERTP Sponsors Rehearing Request at 29-32, 34-35.

[304] Industrial Customers Rehearing Request at 13.

[305] *Id.* at 14.

[306] *Id.* at 15.

[307] *Id.* at 14.

by "beg[inning] with the remedy to show that the *status quo* is not just and reasonable."[308]

116. SERTP Sponsors claim that Order No. 1920's broad conclusion that the regional transmission planning processes conducted by all transmission providers in each transmission planning region are unjust, unreasonable, unduly discriminatory, and preferential is based on the absence of the unique form of long-term regional transmission planning that meets the Commission's current view of what a regional transmission planning process should be.[309] SERTP Sponsors also contend that Order No. 1920 assumes that all regions follow the same generic approach and, while the Commission's *pro forma* transmission planning requirements may be subject to improvement, the Commission has not satisfied its burden of showing that the SERTP regional transmission planning process is unjust and unreasonable.[310]

117. SERTP Sponsors assert that Order No. 1920 imposes its preferred solution in line with the Commission's vision instead of addressing a real need for reform specific to the SERTP regional transmission planning process, thereby imposing a "solution in search of a problem."[311] SERTP Sponsors argue that, in doing so, the Commission misapplied section 206 by collapsing the two-step standard into one step, echoing the mistake

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[308] *Id.* at 15 (citing *Emera Me. v. FERC*, 854 F.3d 9, 22, 25 (D.C. Cir. 2017)).

[309] SERTP Sponsors Rehearing Request at 30.

[310] *Id.* at 31-32.

[311] *Id.* at 30.

described in *Emera Maine*.[312] SERTP Sponsors contend that Order No. 1920 does not demonstrate widespread failures in transmission planning practices, but rather theorizes potential inadequacies in meeting the Commission's desired outcomes.[313] SERTP Sponsors aver that Order No. 1920's discussion of the growing need for transmission investments and perceived insufficiencies of current planning standards does not prove that existing processes fail to meet the evolving demands of the electric grid.[314] SERTP Sponsors allege that the SERTP process has been highly efficient, and that its integrated resource plan and request for proposal-driven transmission planning and other similar processes effectively address the Commission's concerns regarding siloed planning, lack of scenario planning, and local versus regional project focus.[315]

118. SERTP Sponsors argue that Order No. 1920 incorrectly characterizes SERTP's and other similar transmission planning regions' transmission planning processes as deficient due to the absence of alternative regional transmission facilities selected since the implementation of Order No. 1000.[316] SERTP Sponsors contend that the fact that no regional transmission projects have been selected underscores the success of existing integrated resource plan/request for proposal-driven planning systems rather than a

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[312] *Id.* (citing *Emera Me.*, 854 F.3d at 22-26).

[313] *Id.* at 34.

[314] *Id.*

[315] *Id.* at 32.

[316] *Id.* at 35.

failure or deficiency in the regional transmission planning process.[317] SERTP Sponsors also contend that the success of the Southeast's process has been confirmed by the absence of a National Interest Electric Transmission Corridor (NIETC) designation in the Southeast.[318] SERTP Sponsors state that Order No. 1920's attempt to characterize this success as a deficiency collapses the first and second steps of section 206 in the way that the courts have struck down in the past and means that this aspect of the order is unsupported by substantial evidence and is otherwise arbitrary and capricious.[319]

### 2. Commission Determination

119. We conclude that the Commission's section 206 findings, identifying specific deficiencies in regional transmission planning and cost allocation requirements at prong one and establishing specific new requirements at prong two, are – as they are required to be – closely related, in contrast to rehearing parties' arguments. Industrial Customers and SERTP Sponsors' arguments on this point[320] both rely on *Emera Maine,* in which the D.C. Circuit found that the Commission erred in basing its determination that the utility's existing 11.14% base return on equity (ROE) was unjust and unreasonable because it exceeded the 10.57% ROE that the Commission had concluded was the just and

[317] *Id.*

[318] *Id.* at 35-36 (citation omitted).

[319] *Id.* at 36 & n.104 (citations omitted).

[320] Industrial Customers Rehearing Request at 15 (citing *Emera Maine*, 854 F.3d at 9, 22, 25); SERTP Sponsors Rehearing Request at 30 (citing the same).

reasonable base ROE.[321] The court explained that the Commission must first determine that an existing rate is unjust and unreasonable (prong one) before it imposes a replacement rate (prong two).[322] Industrial Customers and SERTP Sponsors argue that, like the Commission's error in *Emera Maine*, Order No. 1920 based its finding that the status quo is unjust and unreasonable on the absence of the Commission's specific desired replacement.[323]

120. When acting under section 206, the Commission must make two findings: (1) that the existing rate, or a practice affecting a rate, is unjust, unreasonable, or unduly discriminatory or preferential; and (2) that the Commission's replacement rate, or practice affecting a rate, is just and reasonable and not unduly discriminatory or preferential.[324] As discussed above, the Commission appropriately made both findings in Order No. 1920, so *Emera Maine* is inapposite.

121. The Commission's findings under the first prong of section 206 do not rely on the specific replacement rate that it created in Order No. 1920. Rather, the Commission's findings under the first prong of section 206 rest on deficiencies, identified based on substantial record evidence, in existing regional transmission planning and cost allocation

[321] *Emera Maine*, 854 F.3d at 25-26.

[322] *Id.* at 25-26.

[323] Industrial Customers Rehearing Request at 15; SERTP Sponsors Rehearing Request at 30.

[324] 16 U.S.C. 824e(a), (b); *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d at 13.

requirements, specifically that they are insufficiently long-term, forward-looking, and comprehensive. The fact that there is a relationship between the deficiencies identified in prong one and the new requirements established as the just and reasonable replacement under prong two of FPA section 206 demonstrates that the replacement regional transmission planning and cost allocation requirements are appropriately tailored toward remedying the deficiencies that the Commission identified in existing regional transmission planning and cost allocation requirements.

122. Order No. 1920 made explicit findings that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential in several respects.[325] First, with regard to long-term regional transmission planning, the Commission noted that most transmission planning regions do not plan beyond a 10-year time horizon.[326] The Commission's finding that a 10-year transmission planning horizon is insufficient does not rely on the Commission's finding that 20 years is the just and reasonable time horizon for Long-Term Regional Transmission Planning. The reasoning underlying the finding that a 10-year transmission planning horizon is insufficient would hold true even if the Commission had determined a different number (e.g., 17 or 25 or 31 years) was the just

[325] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[326] Order No. 1920, 187 FERC ¶ 61,068 at P 115; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

and reasonable replacement. This result is in stark contrast to *Emera Maine*, where the Commission's finding that the existing base ROE was unjust and unreasonable rested entirely on the finding that it did not equal the Commission's replacement ROE.[327] Second, the Commission found, based on substantial evidence, that existing regional transmission planning and cost allocation requirements fail to require transmission providers to adequately account for known determinants of Long Term Transmission Needs.[328] Third, the Commission found, also based on substantial evidence, that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider a sufficiently broad and standard set of benefits of regional transmission facilities.[329] These findings are not based on the precise list of determinants or benefits that the Commission identified in establishing the replacement under of the second prong under FPA section 206, but rather on the conclusion that most transmission providers focus too narrowly on only some determinants and benefits, ignoring other relevant factors, which leads to relatively inefficient or less cost-effective transmission development.[330] Lastly, the Commission's

[327] *Emera Maine*, 854 F.3d at 22.

[328] Order No. 1920, 187 FERC ¶ 61,068 at P 118; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[329] Order No. 1920, 187 FERC ¶ 61,068 at P 122; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[330] Order No. 1920, 187 FERC ¶ 61,068 at PP 122-123.

findings that existing cost allocation requirements are deficient relied on the fact that the Commission's previous cost allocation requirements were tailored to the Order No. 1000 regional transmission planning requirements, but Order No. 1920's new requirements for Long-Term Regional Transmission Planning account for multiple drivers of Long-Term Transmission Needs and result in Long-Term Regional Transmission Facilities that produce a broader set of benefits, and therefore warrant a different approach to cost allocation for such transmission facilities.[331]

123. We also disagree with SERTP Sponsors' contention that Order No. 1920 assumes that all transmission planning regions follow the same generic approach.[332] To the contrary, and as discussed above, Order No. 1920 highlights deficiencies in regional transmission planning processes around the country.[333] Moreover, the Commission found that its existing regional transmission planning and cost allocation *requirements* are unjust and unreasonable.[334] While regions vary in specific approaches, those approaches

[331] *Id.* PP 124-126; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[332] SERTP Sponsors Rehearing Request at 28, 31-34.

[333] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[334] Order No. 1920, 187 FERC ¶ 61,068 at P 114 ("Based on the record, including the comments submitted in response to the NOPR, we find that there is substantial evidence to support the conclusion that *deficiencies in the Commission's existing regional transmission planning and cost allocation requirements* are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential.") (emphasis added)).

are all based on the same requirements. It is those requirements that we continue to find are unjust and unreasonable given the record before us.

124. Additionally, although SERTP Sponsors contend that SERTP's process is highly efficient,[335] the Commission is not required to make findings with respect to individual transmission owners' transmission planning and cost allocation processes to remedy the deficiencies that it determined in Order No. 1920 render its existing regional transmission planning and cost allocation requirements unjust and unreasonable.[336] We also are not persuaded by SERTP Sponsors' argument that the absence of regional transmission facilities selected since the implementation of Order No. 1000 necessarily demonstrates the success of integrated resource plan/request for proposal-driven planning systems instead of a deficiency in regional transmission planning processes.[337] Integrated

[335] SERTP Sponsors Rehearing Request at 32.

[336] *See supra* The Commission Has the Authority to Conduct a Generic Rulemaking section. Moreover, we note that the record reflects disagreement on this point. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 56 ("SREA argues that 'transmission planning in the Southeast has many holes and is threadbare."); *id.* P 115 ("[C]ommenters point out that . . . SERTP . . . plan[s] using a 10-year transmission planning horizon."); *id.* P 333 ("SERTP's 10-year transmission planning horizon prevented Georgia Power from using that process to plan for its long-term North Georgia Reliability & Resilience Plan and its goal to integrate 6,000 MW of renewable resources by 2035."); *id.* P 709 ("Kentucky Commission Chair Chandler argues against SERTP Sponsors' comments that suggest that integrated resource plan/request for proposal processes already consider four of the proposed categories of benefits . . . [and] contends that [those] process[es] can only address these four categories on a utility-by-utility basis and, thus, [are] unable to plan for transmission facilities across utilities or transmission planning regions by nature.").

[337] SERTP Sponsors Rehearing Request at 35.

resource plan/request for proposal-driven planning systems do not replace the need for effective regional transmission planning, as only regional transmission planning ensures consideration of more efficient or cost-effective transmission facilities across utility footprints. We continue to find that "the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs," which results in "transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates."[338]

## IV. Statutory Authority

### A. Order No. 1920 Determination

125. In Order No. 1920, the Commission reaffirmed its conclusion in the NOPR that it was acting within its legal authority under FPA section 206 by requiring transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[339] In doing so the Commission found—and noted that no commenter disputed—that transmission planning and cost allocation processes are practices affecting the rates charged by public utilities in connection with the Commission-jurisdictional transmission of electric energy in interstate commerce.[340]

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[338] Order No. 1920, 187 FERC ¶ 61,068 at P 112.

[339] Order No. 1920, 187 FERC ¶ 61,068 at P 253.

[340] *Id.* (citing 16 U.S.C. 824e; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-59;

126. The Commission disagreed with arguments that the requirements adopted in Order No. 1920 infringe on the authority reserved to the states by FPA section 201 or are otherwise barred by certain prudential or constitutional principles.[341] Noting that it believed that these concerns mainly arose from misunderstandings regarding the substance of Order No. 1920, the Commission explained that Order No. 1920 builds on more than a quarter century of Commission action on transmission planning and cost allocation, which courts have affirmed notwithstanding objections similar to those presented to Order No. 1920, by addressing specific gaps in the existing framework.[342] It emphasized that Order No. 1920 "does not regulate, aim at, or otherwise attempt to influence integrated resource planning, the generation mix, decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states under FPA section 201."[343] To the contrary, Order No. 1920 "directly

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*Emera Me. v. FERC*, 854 F.3d at 673-74).

[341] *Id.* P 254.

[342] *Id.* PP 254-256.

[343] *Id.* P 254; *see also id.* P 257 ("[T]his rule does not mandate development of any particular transmission facility."); *id.* P 258 ("[T]his final rule does not authorize or require any entity to adopt a particular siting plan for Long-Term Regional Transmission Facilities that transmission providers select; or to forego state-jurisdictional siting proceedings where they are necessary; or to begin construction on such Long-Term Regional Transmission Facilities."); *id.* P 259 (explaining that Order No. 1920 "does not change existing mechanisms for cost-recovery through retail rates; authorize or require states or state commissions to change the laws or regulations that govern the conduct of integrated resource planning or request for proposal processes; authorize or require transmission providers or transmission developers to bypass any applicable state-regulated integrated resource planning or request for proposal processes; or authorize or require states or public utilities to adopt a different mix of generation resources"); *id.*

regulates transmission planning and cost allocation processes, . . . directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201."[344] Moreover, Order No. 1920 "is not aiming to *indirectly* regulate any matter reserved to the states by FPA section 201" but, instead, only to improve existing transmission and cost allocation processes to address identified deficiencies with those processes.[345]

127. The Commission explained that these considerations confirmed that Order No. 1920 was well within its authority under the FPA, particularly in light of U.S. Supreme Court precedent in *EPSA*.[346] Applying that decision, the Commission stated that "what matters is that this final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA."[347] In Order No. 1920, the Commission "aim[ed] to improve Commission-regulated transmission planning *processes*, in this instance by ensuring that they are sufficiently long-term, forward-looking, and comprehensive such that they are capable of identifying and meeting Long-

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P 266.

[344] *Id.* P 263.

[345] *Id.*; *see also id.* P 265 ("[T]his final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA.").

[346] *See id.* PP 264-266.

[347] *Id.* P 265.

Term Transmission Needs."[348] Likewise, and consistent with *EPSA*, the Commission found that every aspect of Order No. 1920 "happens exclusively as part of a process that is subject to the Commission's jurisdiction and governs exclusively how those processes work."[349] The Commission further explained that Order No. 1920 does not require that transmission providers achieve any particular substantive outcome of the transmission planning process, aim to alter states' or the nation's generation mix, or otherwise regulate matters within state jurisdiction.[350]

128. The Commission further explained that, applying *EPSA*, Order No. 1920 was within its jurisdiction to regulate the practices affecting the rates for the transmission of electric energy in interstate commerce, notwithstanding that the rule might have effects on matters reserved to state jurisdiction under FPA section 201.[351] The Commission explained that such effects are inevitable—a "fact of economic life" as the Supreme Court put it—given "Congress's decision in the FPA to divide jurisdiction over the

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[348] *Id.*

[349] *Id.* P 266 (quotation marks omitted).

[350] *Id.*; *cf. id.* P 267 (also rejecting arguments that Order No. 1920 required states to subsidize other state's public policies, explaining that Order No. 1920 required following long-extant precedent that transmission customers need only pay costs that are "roughly commensurate" with the benefits received from a regional transmission facility).

[351] *Id.* P 264 (explaining that such effects are of "'no legal consequence'" (quoting *EPSA*, 577 U.S. at 281)); *see id.* P 262 n.612 (quoting *EPSA*, 577 U.S. at 281-82 ("When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, *then no matter the effect* on retail rates, [16 U.S.C.] 824(b) imposes no bar." (emphasis added))).

industry, including both generation and transmission, into spheres of Commission and state jurisdiction that are not 'hermetically sealed' from one another."[352]

129. The Commission therefore disagreed with arguments that Order No. 1920 unlawfully intruded on areas of reserved state authority under FPA section 201.[353] The Commission stated that Long-Term Regional Transmission Planning "necessarily involves taking into account assumptions about the generation resources that will be available, because transmission needs arise from the relative amounts, locations, and timing of supply (i.e., generation) and of demand (i.e., load)."[354] It stated that the effects of such planning on areas of state authority, however, do not divest the Commission of the jurisdiction Congress conferred on it to regulate the transmission of electric energy in interstate commerce.[355]

130. The Commission was also not persuaded by arguments that Order No. 1920 was unlawful under the "major questions doctrine."[356] It found that commenters were misinterpreting the Supreme Court's decision in *West Virginia v. EPA* as suggesting that,

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[352] *Id.* (quoting *EPSA*, 577 U.S. at 281); *see id.* P 272 ("We acknowledge that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable.").

[353] *See id.* PP 271-274.

[354] *Id.* P 272 (noting also that existing transmission planning processes already take these assumptions into account, and that Order No. 1920 "simply modifies the scope and duration of these assumptions" to ensure more effective transmission planning).

[355] *See id.* PP 264, 271-272.

[356] *See id.* PP 275-279.

in every instance, agency regulations affecting energy policy and the generation mix are "major questions" requiring direct authorization from Congress.[357] Rather, the Commission stated that the Supreme Court in that decision considered a specific United States Environmental Protection Agency (EPA) action in light of a particular statutory provision and concluded that this action implicated the major questions doctrine based on a variety of factors specific to that context.[358] The Commission noted that commenters had not analyzed whether Order No. 1920 would, based on the factors the Supreme Court examined, constitute a major question; when the Commission considered those factors, it concluded that Order No. 1920 would not implicate the major questions doctrine.[359] Among other things, the Commission found that Order No. 1920, as an incremental improvement building on past regulation, did not represent a transformative expansion of the Commission's regulatory authority and did not have vast economic or political significance;[360] did not resemble EPA's assertion of authority related to the electric

[357] *Id.* PP 275-276.

[358] *Id.* P 276 (noting that these factors "include[d] whether the EPA's administrative action was a 'transformative' expansion of its power, whether the EPA had relevant technical and policy expertise, whether the relevant statutory provision was 'ancillary' to the broader statutory construct, and whether the EPA's administrative action implicated significant economic and political questions" (citing *W.V. v. EPA*, 597 U.S. 697, 710, 724-25, 729, 731-32 (2022) (*West Virginia*)).

[359] *See id.* PP 277-279.

[360] *See id.* PP 277-278.

system;[361] was not reliant on a "backwater" statutory provision; and was not promulgated notwithstanding Congress's repeated rejection of legislation to enact reforms similar to those in the rule.[362]

131. The Commission also disagreed with arguments that Order No. 1920 effectively required certain states to subsidize other states' vision of what resources should be used in electricity generation and, therefore, violated the Constitution's "equal sovereignty doctrine."[363] Here, the Commission again explained that Order No. 1920 "categorically does not require states to subsidize other states' public policies or generation decisions," but rather was consistent with longstanding cost-causation principles.[364] Moreover, the Commission pointed out that no court has ever applied the equal sovereignty doctrine invoked by commenters as a limit on Congress's Article I powers, including legislation enacted under the Commerce Clause, such as the FPA.[365]

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[361] *Id.* P 279.

[362] *See id.*

[363] *See id.* PP 280-282.

[364] *Id.* P 280.

[365] *See id.* P 281 (noting that the FPA, in turn, "empowers the Commission to regulate the rates and practices affecting rates for the transmission of electricity in interstate commerce").

### B. Federal/State Division of Authority

#### 1. Requests for Rehearing

132. Several of the requests for rehearing argue that Order No. 1920 exceeds the Commission's statutory authority under FPA section 206 and is, therefore, unlawful.[366] Many of these requests for rehearing acknowledge the Commission's authority under the FPA over "the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce."[367] However, rehearing parties argue that the Commission's jurisdiction "extend[s] only to those matters which are not subject to regulation by the States" and that the Commission, with certain exceptions, "shall not have jurisdiction . . . over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce."[368] Undersigned States and Designated Retail Regulators also state

[366] *See* Undersigned States Rehearing Request at 2-3, 6, 10-13, 17; Designated Retail Regulators at 2-3, 6, 11-15, 18; Alabama Commission Rehearing Request at 5; Georgia Commission Rehearing Request at 3-4; Arizona Commission Rehearing Request at 2, 9-12, 15; Idaho Commission Rehearing Request at 2, 4-5; Montana Commission Rehearing Request at 1-4; Wyoming Commission Rehearing Request at 1-4; Utah Commission Rehearing Request at 1, 3-7; West Virginia Commission Rehearing Request at 3-4, 10-12.

[367] 16 U.S.C. 824(b)(1); *see also* 16 U.S.C. 824d(a), 824e(a); Undersigned States Rehearing Request at 10-11 (arguing that the FPA is "primarily, and perhaps exclusively, an *economic* regulation statute"); Designated Retail Regulators at 12 (same); Alabama Commission Rehearing Request at 5; Arizona Commission Rehearing Request at 10; Utah Commission Rehearing Request at 3.

[368] 16 U.S.C. 824(a), (b)(1); *see* Undersigned States Rehearing Request at 11; Designated Retail Regulators at 12-13; Alabama Commission Rehearing Request at 5 (asserting that the Commission's jurisdiction does not extend to "electric power generation, transmission siting, distribution, retail supply, and service models," including

that FPA section 215(i)(3) reserves jurisdiction to the states over the "safety, adequacy, and reliability of electric service."[369] Designated Retail Regulators aver that the Commission's authority is limited by the National Interest Electric Transmission Corridor process.[370]

133. Several rehearing requests posit that Order No. 1920 exceeds the Commission's authority because it invades or undermines state authority over the choice of generating resources maintained or constructed within each state's jurisdiction.[371] Undersigned States and Designated Retail Regulators argue that Order No. 1920 "puts into place planning processes that will favor renewables over other generation and ignore the

"oversight of the IRP process and the associated selection of resources to provide reliable retail service"); Arizona Commission Rehearing Request at 10-11; Idaho Commission Rehearing Request at 4; Montana Commission Rehearing Request at 2-3.

[369] 16 U.S.C. 824o(i)(3); Undersigned States Rehearing Request at 11; Designated Retail Regulators Rehearing Request at 13.

[370] Designated Retail Regulators Rehearing Request at 18-19 (citing 16 U.S.C. 824p).

[371] *See* Undersigned States Rehearing Request at 11-13 (citing *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 212 (1983); *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan.*, 489 U.S. 493, 522 (1989); *Monongahela Power Co.*, 40 FERC ¶ 61,256, at 61,861 (1987); *Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035 (2020) (Glick, Comm'r, dissenting at P 5)); Designated Retail Regulators Rehearing Request at 13-14; Idaho Commission Rehearing Request at 4; Utah Commission Rehearing Request at 3-5; West Virginia Commission Rehearing Request at 11; Arizona Commission Rehearing Request at 10-11; *cf. id.* at 2-3 ("'The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities.'" (quoting *Piedmont Envt'l Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009)).

combined generation/transmission benefits that other solutions could provide."[372] They argue that this will result in "shift[ing] costs to deliver those renewables to customers that do not cause those costs to be incurred and that have selected other generation options with different transmission requirements."[373] In this vein, Undersigned States and Designated Retail Regulators assert that "[r]equiring customers in states to pay for infrastructure to support the public policies and generation resource mixes chosen by other states, without demonstrable benefits to that load, would be a major intrusion on the States' right to choose the resources that best fit their public policies."[374]

134. Many of the other arguments challenging the Commission's statutory authority proceed along similar lines. Alabama Commission argues that the Commission in Order No. 1920 is "putting a 'thumb on the scale' and intruding on resource selection in

[372] Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14-15; *see also* Undersigned States Rehearing Request at 3-4 (arguing that Order No. 1920's "building-block concepts ('Sufficiently long-term,' 'Long-Term Transmission Needs,' 'known determinants of Long-Term Transmission Needs,' the 'broader set of benefits,' and particularly, the inputs to this elaborate scheme) mandate new planning processes for transmission facilities that are designed to (1) move remote renewables over long distances and (2) socialize their costs"); *id.* at 27-29; Designated Retail Regulators Rehearing Request at 3-4, 27-28 (similar).

[373] Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14-15; *see also* Undersigned States Rehearing Request at 33-34.

[374] Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 14; *see also id.* at 38 ("FERC has no statutory authority to pick winners and losers among differing types of generation or use the cost allocation process as an alternative means to dilute financial responsibility for policy decisions.").

Alabama."[375] Georgia Commission contends that in Order No. 1920 the Commission is acting as a national integrated resource planner, attempting to change the future generation mix,[376] and will require states to subsidize the renewable generation policies of other states.[377] Arizona Commission argues that the Commission lacks "jurisdiction to impose mandated energy policies for intrastate distribution or to foist costs on rate payers for costs created in other states."[378] Idaho Commission asserts that certain of the categories of factors that transmission providers must consider in developing Long-Term Scenarios will "disproportionately favor certain projects in the planning process, provide disparate treatment to states' policy goals, affect resource planning and selection at the state level, and infringe on states' authority with respect to generation."[379] Montana Commission, Wyoming Commission, and West Virginia Commission argue that, absent a voluntary State Agreement Process, the cost allocation approach in Order No. 1920

[375] Alabama Commission Rehearing Request at 5.

[376] Georgia Commission Rehearing Request at 3-4 (arguing that Order No. 1920 violates states' reserved decision-making power by requiring that they "measure their long-term transmission plans against seven factors identified in the Order," because these factors allegedly favor certain policies and projects).

[377] *Id.* at 5-6.

[378] Arizona Commission Rehearing Request at 11-12 (citing *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 210 (1964), for the proposition that Congress intended to draw an easily ascertained bright line between state and federal jurisdiction); *id.* at 13; *cf. id.* at 6-7 (arguing that "nothing in federal jurisprudence or the FPA allows FERC to usurp these traditional state functions of intrastate transmission and balancing such energy source costs with ratepayer fairness").

[379] Idaho Commission Rehearing Request at 4-5.

ensures that nonconsenting states will be swept up in their neighbors' preferred policy projects, invading the jurisdiction of states.[380] Utah Commission argues that the Commission stated its intention in the ANOPR and NOPR to unlawfully influence the generation mix.[381] It claims that Order No. 1920 "effectively rigs the planning and cost allocation process to ensure (i) FERC's preferred stakeholders' projects are selected in the planning process and (ii) these preferred stakeholders are not required to bear the full costs associated with their choices."[382]

### 2. Commission Determination

135. We appreciate these concerns articulated on rehearing and believe several clarifications that we adopt below will alleviate these concerns. Nonetheless, we sustain the Commission's determination that Order No. 1920 is a valid exercise of our statutory authority under the FPA and does not unlawfully intrude into areas of reserved state

[380] Montana Commission Rehearing Request at 2-4 (citing *EPSA*, 577 U.S. at 295-96; *Pac. Gas & Elec. Co.*, 461 U.S. at 212; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56-59; Wyoming Commission Rehearing Request at 2-4 (similar); West Virginia Commission Rehearing Request at 3-4, 10-12 (similar, also arguing that "[w]ithout a meaningful voluntary state agreement process, the Commission erred by exceeding its jurisdiction and interfering with state decisions about generation resource planning and approval").

[381] Utah Commission Rehearing Request at 4-5.

[382] *Id.* at 5-6 (arguing that Order No. 1920 "precludes transmission planners and cost allocation from distinguishing between transmission projects that are necessary to resolve an identified reliability or economic concern from those that are only necessary because some state, local government, or corporation has unilaterally adopted a policy"); *see id.* at 8 ("[T]he FPA gives FERC no authority to regulate electricity generation and specifically reserves that power to the states.").

authority.[383] In arguing to the contrary, the rehearing requests fail to meaningfully address the substance of Order No. 1920 and fail to respond to the Commission's explanation for why that rule falls within its jurisdiction. Instead, they misconstrue that rule as attempting to control or influence the generation mix in favor of allegedly Commission-preferred resources.[384] Moreover, the arguments on rehearing are unjustified as a legal matter as they fail to apply *EPSA* to Order No. 1920 (and in many cases, do not even acknowledge this controlling precedent).[385] They also depend on the mistaken view that the policies of one state may not have permissible extraterritorial

[383] Order No. 1920, 187 FERC ¶ 61,068 at PP 253-54.

[384] *See, e.g.*, Undersigned States Rehearing Request at 3-4, 12-13; Designated Retail Regulators Rehearing Request at 11-15; Georgia Commission Rehearing Request at 3-4; Idaho Commission Rehearing Request at 2, 4-5; Alabama Commission Rehearing Request at 5; Arizona Commission Rehearing Request at 2, 11-12, 15; Montana Commission Rehearing Request at 3-4; Wyoming Commission Rehearing Request at 3-4; West Virginia Commission Rehearing Request at 12; Utah Commission Rehearing Request at 1, 3-7.

[385] *See* Designated Retail Regulators Rehearing Request at 3-4, 6, 11-15 (no citation of *EPSA*); Georgia Commission Rehearing Request at 3-4 (same); Idaho Commission Rehearing Request at 2, 4-5 (same); Arizona Commission Rehearing Request at 2, 9-12, 15 (same); Alabama Commission Rehearing Request at 5 (same); Utah Commission Rehearing Request at 1, 3-7; Undersigned States Rehearing Request at 14 (citing *EPSA* as recognizing the steady flow of jurisdictional disputes under the FPA); Montana Commission Rehearing Request at 3 (citing *EPSA* as establishing that "FERC regulation of jurisdictional subject matters (wholesale sales and transmission) may influence matters within the states' power to regulate"); Wyoming Commission Rehearing Request at 2-3 (same); West Virginia Commission Rehearing Request at 11 (same).

effects on other states through interstate commerce, including in the context of interstate transmission of electricity as regulated under the FPA.[386]

### a. Order No. 1920 Does Not Attempt to Control the Generation Mix or Intrude in Areas of State Authority

136. We begin our discussion of the Commission's statutory authority to issue Order No. 1920 with the substance of Order No. 1920. In broad strokes, Order No. 1920 required transmission providers to "(1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs."[387] As affirmed by the D.C. Circuit, regional transmission planning and cost allocation processes are practices directly affecting rates subject to the Commission's sole jurisdiction, as transmission providers "use those processes to 'determine which transmission facilities will more efficiently or cost-effectively meet' transmission needs."[388]

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[386] *See, e.g.*, Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 11, 14; Utah Commission Rehearing Request at 12; West Virginia Commission Rehearing Request at 12; *see also infra* Order No. 1920 Does Not Require Unlawful Subsidization of State Policies section.

[387] Order No. 1920, 187 FERC ¶ 61,068 at P 1; *see also id.* PP 224-248.

[388] *Id.* P 86 (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56); *id.* ("[T]hese processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates . . . .").

137. In light of the direct effects that transmission planning processes have on Commission-jurisdictional rates, "the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000."[389] Order No. 1920 thus does not stand in a vacuum, but rather "build[s] upon more than a quarter century of significant actions taken by the Commission on transmission planning and cost allocation,"[390] particularly by addressing specific gaps in the existing regional transmission planning process set forth in Order No. 1000.[391]

138. Order No. 1920 required transmission providers to conduct Long-Term Regional Transmission Planning to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.[392] To identify these Long-Term Transmissions Needs and transmission facilities that meet such needs, transmission providers must develop a set of at least three plausible and diverse Long-Term Scenarios, using the best available data inputs about the future electric power system, over a transmission planning

[389] *Id.* P 14; *see also id.* PP 15-19 (describing the reforms in Order No. 1000).

[390] *Id.* P 255.

[391] *Id.* P 256; *see also id.* PP 257-259 (describing how Order No. 1920 is consistent with the approach in Order No. 1000, including in that Order No. 1920 does not mandate the development of particular transmission facilities, intrude on siting processes for transmission facilities, or change existing mechanisms for cost recovery); *id.* P 266.

[392] *Id.* P 38; *see also id.* PP 1-13, 225.

horizon of no less than 20 years.[393] In developing such scenarios, transmission providers must consider certain known determinants of transmission needs, which the Commission identified in Order No. 1920 as falling within seven categories of factors that affect Long-Term Transmission Needs.[394]

139. The categories of factors the Commission identified were "(1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs."[395] The Commission identified these categories of factors because they provide information about the drivers of Long-Term Transmission Needs, including changes in reliability needs, demand, and supply (such as the generation resource mix)

[393] *See id.* PP 40, 248.

[394] *See id.* PP 248, 387-537.

[395] *Id.* P 409. As discussed below, we are setting aside the requirement in Factor Category Seven to consider corporate commitments. *See infra* Requests to Omit One or More Specific Categories of Factors section. That change does not affect our conclusion as to the Commission's statutory authority, including our response to the arguments on rehearing addressing the federal/state division of authority under the FPA.

that, in turn, affect what transmission facilities will be required going forward.[396] The Commission stated that transmission providers have discretion, however, to consider additional factors[397] and may, in developing their Long-Term Scenarios, find that any factor is not, in fact, likely to affect Long-Term Transmission Needs.[398]

140. Under Order No. 1920, transmission providers must also identify and evaluate transmission facilities to meet such Long-Term Transmission Needs and for potential selection as Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[399] Here, the Commission required that transmission providers measure and use at least seven specified benefits as part of that analysis,[400] which measurement reflects "the value that the transmission providers expect a particular Long-Term Regional Transmission Facility to provide to transmission customers in the transmission planning region."[401] The Commission provided transmission providers with extensive flexibility in the measurement of such benefits.[402]

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[396] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 90-111, 299-300, 432, 440, 447, 456, 463, 472, 481.

[397] *See id.* P 412.

[398] *See id.* PP 415, 417.

[399] *See id.* PP 1-3, 40, 225, 719-720.

[400] *See id.* P 3; *see also id.* PP 729, 737.

[401] *Id.* P 269; *see also id.* P 720 (identifying the benefits to be considered).

[402] *See, e.g.*, *id.* PP 728, 735, 839.

141. The Commission also required transmission providers to "file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected."[403] It provided a process for robust participation by Relevant State Entities to seek to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[404] However, the Commission found that "[w]hile we permit transmission providers to include a State Agreement Process in their OATTs . . . it cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities,"[405] and required that "the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop."[406]

142. The bases for the reforms in Order No. 1920 are entirely focused on improving Commission-jurisdictional processes. The Commission found that existing transmission planning and cost allocation processes are inadequate, such that "transmission providers are often not identifying, evaluating, or selecting more efficient or cost-effective regional

[403] *Id.* P 5; *see also id.* P 43 (defining Long-Term Regional Transmission Cost Allocation Method); *id.* P 1291.

[404] *See id.* PP 5, 1291.

[405] *Id.* P 1292; *see id.* P 1293 (explaining that, if transmission providers were to rely solely on a State Agreement Process, this gives rise to the possibility there would be no cost allocation method for Long-Term Regional Transmission Facilities such that selected facilities would be less likely to be developed and their benefits less likely to be realized).

[406] *Id.* P 1292.

transmission solutions to meet Long-Term Transmission Needs."[407] Trends in "economics, growing demand, and federal, federally-recognized Tribal, state, and local policies [that] are already resulting in significant changes in the resource mix"[408] have reinforced that more effective transmission planning "helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent."[409] In fact, "in the limited instances in which transmission providers have followed processes that share many of the elements of the long-term, forward-looking, and more comprehensive regional transmission planning this rule requires, customers have seen clear and quantifiable benefits."[410] In issuing Order No. 1920, the Commission was thus acting in a responsive capacity to account for observable, large-scale, and preexisting trends driven by external forces, which highlighted the need for improved transmission planning and cost allocation processes.[411]

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[407] *Id.* P 87.

[408] *Id.* P 99 (noting that "as of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources" whereas most capacity retirements were from coal resources, with these trends projected to continue); *see also id.* PP 94-98 (discussing trends that shape transmission needs and reflect the need for more efficient and cost-effective transmission planning).

[409] *Id.* P 100 ("Conversely, inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill . . . ."); *see also, e.g.*, *id.* PP 103-06, 121, 123, 236; *cf. id.* P 101 (discussing that existing transmission planning requirements have "yielded only limited investments in regional transmission projects").

[410] *Id.* P 102.

[411] *See, e.g.*, *id.* P 129 ("[T]he Commission is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's

143. As this summary reflects,[412] Order No. 1920 directly regulates transmission planning and cost allocation processes, effectuating one of the "core objects" of the FPA, as identified by the Supreme Court: "ensur[ing] effective transmission of electric power."[413] And the parties arguing that Order No. 1920 unlawfully intrudes into reserved areas of state authority do not identify any aspect of Order No. 1920 that is not, on its face, directed toward these Commission-jurisdictional targets.[414] Rather, they argue that Order No. 1920 intrudes on state resource selection because, in regulating such *transmission* planning and cost allocation, Order No. 1920 is purportedly biased toward the construction of transmission facilities that will serve allegedly Commission-favored resources, which will in turn affect the generation resource mix.[415] Here, they focus on

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jurisdiction or control . . . ."); *id.* P 130; *id.* P 261 ("[T]his final rule *responds* to changes in the electric industry that have arisen in the years since the Commission's last regulatory action related to transmission planning.").

[412] This summary addresses aspects of Order No. 1920 as pertinent to the challenges to the Commission's statutory authority raised on rehearing.

[413] *EPSA*, 577 U.S. at 290; *see also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 57 ("Reforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities . . . involves a core reason underlying Congress' instruction in Section 206.").

[414] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 265-66.

[415] *See* Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14; Georgia Commission Rehearing Request at 3-4; Arizona Commission Rehearing Request at 9-12, 15; Idaho Commission Rehearing Request at 4-5; Utah Commission Rehearing Request at 4-5; Montana Commission Rehearing Request at 3-4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 3-4; Alabama Commission Rehearing Request at 5; *cf.* Ohio Commission Federal Advocate Rehearing Request at 18-20 (asserting that, in doing so,

the categories of factors that the Commission identified as reflecting known determinants of transmission needs, arguing that certain of these factors are not resource neutral.[416]

144. The rhetoric in the rehearing requests suggesting that the Commission exceeded its statutory authority by directing reforms targeted at certain transmission planning outcomes demonstrates a misunderstanding of Order No. 1920, and particularly the categories of factors.[417] The Commission found that the categories of factors set forth in Order No. 1920 reflect known determinants of transmission needs,[418] such that requiring that transmission providers consider these factors in Long-Term Regional Transmission Planning is appropriate and reasonable. The substantive content of these factors (for example, a state law or policy implementing the state's reserved authority over resource

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the Commission is violating the Commerce Clause of the Constitution).

[416] *See* Undersigned States Rehearing Request at 10-13, 27-28 (arguing that Order No. 1920 and that the categories of factors, in particular, "are not resource neutral"); Designated Retail Regulators Rehearing Request at 14-15, 26-28 (same); Georgia Commission Rehearing Request at 4; Idaho Commission Rehearing Request at 4-5; Ohio Commission Federal Advocate Rehearing Request at 18-20; Utah Commission Rehearing Request at 4-5; Montana Commission Rehearing Request at 3-4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 3-4.

[417] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 260 ("In this final rule, the Commission neither aims to influence the resource mix, nor, as a practical matter, could the final rule achieve such an outcome."); *see also id.* PP 129-30, 254, 419; *cf. Dep't of Com. v. N.Y.*, 588 U.S. 752, 780–81 (2019) ("A court is ordinarily limited to evaluating the agency's contemporaneous explanation in light of the existing administrative record."); *Pharm. Rsch. & Mfrs. of Am. v. F.T.C.*, 790 F.3d 198, 212 (D.C. Cir. 2015) (noting the presumption of procedural regularity and substantive rationality that attaches to final agency action).

[418] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 119-120, 130, 412, 415; *see also id.* PP 422-84 (discussing the adoption of the specific categories of factors).

choices) and how they affect transmission providers' development of Long-Term Scenarios (for example, the extent to which they may lead to the identification of specific Long-Term Transmission Needs) will be attributable to exogenous forces independent of Commission action.[419] Indeed, these forces are drivers of the pre-existing trends, discussed above, that have demonstrated the urgency of more effective transmission planning.[420] In other words, the Commission is not requiring consideration of these factors in order to achieve particular outcomes in the transmission planning process, but rather acting in a responsive capacity to identify and account for the most likely variables that are relevant to effective Long-Term Regional Transmission Planning and ensure that those variables are considered in such planning.[421]

145. Factor Category One (federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand) is illustrative,[422] although these same points also apply to the other categories of factors. Because such laws and

[419] *See id.* PP 129-130, 233, 261-62, 419, 436.

[420] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[421] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 230, 266.

[422] *See id.* P 130 n.328 (citing *PJM Power Providers Grp. v. FERC*, 88 F.4th 250, 275 (3d Cir. 2023) (holding that the Commission is "unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus . . . ."); *Elec. Power Supply Ass'n v. Star*, 904 F.3d at 524 (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois "as givens and set out to make the best of the situation [these systems] produce")).

regulations, by definition, "affect[ ] the resource mix and demand" and, in turn, changes in resource mix and demand can affect Long-Term Transmission Needs,[423] these laws and regulations are relevant to determining such transmission needs. The effect of such laws and regulations on transmission needs is inevitable[424] and would be the same even in the absence of Order No. 1920.[425] Furthermore, the existence and content of such laws and regulations are independent of any Commission action, as they are attributable instead to the lawful exercise of the authority of the entities, including states, responsible for enacting or promulgating such laws and regulations. Order No. 1920 thus requires Long-Term Regional Transmission Planning that *accounts* for the effects of these laws and regulations on transmission needs, because failure to adequately do so has had, and

[423] We note that the arguments on rehearing require recognizing that different types of generating resources, located in different areas, may have different transmission needs. *See, e.g.*, Undersigned States Rehearing Request at 10, 16. In this respect, the rehearing requests tend to reinforce, rather than rebut, that the categories of factors set forth in Order No. 1920 are salient considerations for effective transmission planning.

[424] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 435 ("Rather than a unique feature of Long-Term Regional Transmission Planning, transmission planning of any kind will inherently reflect the policy choices of multiple decisionmakers, because the quantity and location of generation and load are shaped by multiple decisionmakers.").

[425] *See id.* P 436 (explaining that "because . . . Long-Term Transmission Needs driven by disparate policy decisions would continue to exist, regardless of whether they were identified in Long-Term Regional Transmission Planning, failing to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs will result in unjust and unreasonable rates").

will continue to have, significant deleterious consequences.[426] Order No. 1920 does not create these effects or aim to influence them.

146. Contrary to claims in the rehearing requests,[427] the categories of factors set forth in Order No. 1920 are also resource-neutral. Factor Category One is, again, illustrative. To the extent a law or regulation affects the resource mix or demand, transmission providers must consider how that law or regulation may affect Long-Term Transmission Needs. This requirement applies to all laws and regulations falling within Factor Category One, irrespective of their substantive content.[428] Thus, to the extent a state law may affect the resource mix because, for example, it encourages or discourages the development of *any* particular type of generation, that would be a relevant consideration in Long-Term Regional Transmission Planning.[429] This same point applies to all of the categories of factors specified in Order No. 1920: transmission providers must consider those

[426] *See id.* PP 130, 233, 261-262.

[427] *See supra* P 143 n.416.

[428] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 437 ("We are not endorsing the merits of any specific federal, federally-recognized Tribal, state, or local laws and regulations or of any specific state-approved integrated resource plans. We emphasize that the Commission's policies are technology neutral, and we are not establishing a preference for certain types of generation or energy end uses.").

[429] Similarly, where a state has laws or regulations that are, themselves, resource neutral or lacks laws or regulations affecting the generation mix or demand, the relevant transmission providers must conduct their Long-Term Regional Transmission Planning considering those considerations.

categories of factors in developing Long-Term Scenarios irrespective of the substantive content of any given factor in a category.

147. In this respect, the categories of factors identified in Order No. 1920 are best understood as a non-exhaustive identification of essential inputs relevant to Long-Term Regional Transmission Planning. To the extent that, in developing any Long-Term Scenarios, these inputs may point toward identification of particular Long-Term Transmission Needs, this will be the result of external forces that determine the substance of these inputs. In fact, the evaluation of these inputs will be conducted by transmission providers in consultation with relevant stakeholders without the Commission imposing any requirements that dictate the substantive outcome of the transmission planning process.[430] Indeed, all the requirements that the Commission has established for conducting Long-Term Regional Transmission Planning—such as the number of Long-Term Scenarios to be developed, the time horizon to be considered, that scenarios be "plausible and diverse," and that the best available data be used—are also process-focused and resource-neutral.[431]

148. Moreover, the discretion afforded to transmission providers in conducting their analyses further precludes the Commission from attempting to "put a thumb on the scale"

[430] We further strengthen those consultation requirements in this order by requiring transmission providers to consult with and consider the positions of Relevant State Entities as to how to account for factors related to state public policies in Long-Term Regional Transmission Planning assumptions.

[431] *See id.* P 248 (summarizing those process-focused requirements).

of the transmission planning process to favor certain generation resources. Transmission providers may consider additional factors, beyond those specified in the categories of factors set forth in Order No. 1920, in developing Long-Term Scenarios and identifying Long-Term Transmission Needs.[432] Transmission providers also "have discretion to determine whether specific factors must be accounted for within each category (i.e., if the specific factor will likely affect Long-Term Transmission Needs)."[433] Thus, the categories of factors set forth in Order No. 1920 reflect minimum standards that transmission providers may not ignore when developing Long-Term Scenarios. However, as long as these scenarios otherwise meet the requirements of Order No. 1920 (e.g., they are plausible and diverse), Order No. 1920 ensures that transmission providers may consider *all* of the relevant factors and may also determine, in any given case, that any factor is *not* likely to affect such needs. This construct is wholly consistent with resource-neutral transmission planning.[434]

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[432] *See id.* P 412.

[433] *See id.* P 417 (further providing that transmission providers must "assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities identified in the first three categories of factors—that transmission providers have determined are likely to affect Long-Term Transmission Needs—are fully met"); *see also id.* P 415.

[434] Transmission providers also have discretion regarding "how to account for specific factors in the development of Long-Term Scenarios (e.g., the method and data used to forecast resource retirements), and how to vary the treatment of each category of factors across Long-Term Scenarios (e.g., assume all forecasted resource retirements materialize in some but not all Long-Term Scenarios)." *Id.* P 417.

149. Certain rehearing requests state that other aspects of Order No. 1920 (such as the seven required benefits to evaluate Long-Term Regional Transmission Facilities) are preferential toward allegedly Commission-favored resources. These arguments are not well developed.[435] Nonetheless, based on our best understanding of these arguments, we disagree with them for reasons similar to those articulated above and in Order No. 1920. Requiring that transmission providers measure and use, at a minimum, the seven required benefits in evaluating Long-Term Regional Transmission Facilities does not attempt to influence the external forces driving the need for new transmission facilities or displace the authority of other actors. Rather, this requirement helps to ensure that transmission providers conducting Long-Term Regional Transmission Planning have sufficient information to make their decisions, including as to which Long-Term Regional Transmission Facilities will "more efficiently or cost-effectively address Long-Term Transmission Needs."[436] Here, too, the Commission's approach has not been overly prescriptive, as transmission providers may propose on compliance to measure additional

[435] *See, e.g.*, Undersigned States Rehearing Request at 3-4, 8, 27-29 (asserting that the "factors and benefit metrics" will "favor some resources over others"; arguing that particular factors are not "resource neutral" but no similar argument or explanation as to the benefits metrics); Designated Retail Regulators Rehearing Request at 3-4, 8, 26-29 (similar); Arizona Commission Rehearing Request at 15.

[436] Order No. 1920, 187 FERC ¶ 61,068 at PP 667, 721; *see also id.* P 722 ("[W]ithout consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs."); *id.* P 723.

benefits as part of Long-Term Regional Transmission Planning[437] and the Commission has afforded transmission providers flexibility as to how to measure each required benefit.[438]

150. Thus, Order No. 1920 reflects a modest exercise of well-established Commission authority. To be sure, there is an urgent and growing need for new transmission infrastructure, driven by a wide variety of factors, including those leading to changes in the generation resource mix.[439] Order No. 1920 identifies those factors, which are occurring independent of Commission action, and gives transmission providers the tools they need to respond to this need and these changes.[440] The parties that argue that the Commission is attempting to influence the generation resource mix by requiring transmission providers to consider these factors to inform their Long-Term Regional Transmission Planning are reversing cause and effect that necessitated the issuance of Order No. 1920.[441]

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[437] Order No. 1920, 187 FERC ¶ 61,068 at P 667.

[438] *Id.* P 728; *cf. id.* P 734 ("[W]hile this final rule requires the measurement and use of the required set of benefits, it is the evaluation process, including selection criteria, that transmission providers propose on compliance that will inform which Long-Term Regional Transmission Facilities are selected.").

[439] *See id.* PP 90-99.

[440] *See id.* P 233 ("These changes are occurring independent of any action that we take in this final rule, and they are being driven by a wide variety of factors. This final rule provides transmission providers with the tools that they need to respond to these factors . . . .").

[441] Claims that the Commission "advertised" its "unlawful purpose" in the ANOPR and NOPR, *see* Utah Commission Rehearing Request at 4-5, are erroneous for

### b. Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority

151. As discussed above, in filling the discrete gaps in the Order No. 1000 regional transmission planning and cost allocation process, the Commission carefully tailored the reforms it adopted to avoid intruding on areas of reserved state authority. But because the spheres of federal and state authority over electricity are not "hermetically sealed" from one another,[442] we recognize the possibility that Order No. 1920's requirements—although entirely focused on addressing practices within the Commission's jurisdiction—may have effects on areas of reserved state authority.

152. While the rehearing requests discuss the text of the FPA and precedent reflecting that states have reserved authority in certain areas, including over the selection and approval of generation resources, they fail to discuss key Supreme Court precedent in *EPSA* as it applies Order No. 1920. Despite the Commission's lengthy discussion of *EPSA* in Order No. 1920, on rehearing we are confronted with no argument that the Commission erred in its analysis or misapplied that decision to the facts here.

153. Under the FPA, the Commission has exclusive jurisdiction over "the transmission of electric energy in interstate commerce," and "the sale of electric energy at wholesale in

much the same reason: they misconstrue statements in which the Commission discussed the need for transmission reform to respond to changes in the resource mix driven by external factors, including increased penetration of renewable resources, as indicative of an intention to drive such changes.

[442] *EPSA*, 577 U.S. at 281.

interstate commerce."[443] The Supreme Court has "construed broadly" this grant of jurisdiction over interstate transmission of electricity.[444] Under this grant of authority, "ensur[ing] effective transmission of electric power" is one of the "core objects" of the FPA.[445] FPA section 206 is one of the principal tools Congress afforded the Commission to exercise this authority, under which it may find that practices affecting Commission-jurisdictional rates are "unjust, unreasonable, unduly discriminatory or preferential," and determine the just and reasonable practice to be thereafter observed and in force.[446] As the D.C. Circuit has recognized, the authority afforded to the Commission under FPA section 206 is "broadly stated" and not a "subtle device."[447]

154. The Commission does not, however, have jurisdiction over "facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter," except as

[443] 16 U.S.C. 824(b)(1) ("The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy . . . .").

[444] *N.Y. v. FERC*, 535 U.S. at 15.

[445] *EPSA*, 577 U.S. at 290.

[446] 16 U.S.C. 824e(a).

[447] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56 ("The authority and obligation that Congress vested in the Commission to remedy certain practices is broadly stated and the only question is what limits are fairly implied."); *see also id.* at 55 ("The text does not define 'practice,' although use of the word 'any' amplifies the breadth of the delegation to the Commission.").

specifically provided.[448] FPA section 201 also contains a policy statement recognizing the need for Federal regulation in areas subject to the Commission's jurisdiction, but also providing that "Federal regulation, however, [is] to extend only to those matters which are not subject to regulation by the States."[449] Thus, as the rehearing requests point out, courts and the Commission have recognized certain reserved areas of state authority, including over electricity generation.[450]

155. Under *EPSA*, Order No. 1920 is a lawful exercise of the Commission's authority because it regulates practices that directly affect the rates for the transmission of electric energy in interstate commerce—transmission planning and cost allocation processes—

[448] 16 U.S.C. 824(b)(1).

[449] *Id.* 824(a). This policy statement does not nullify the grant of authority to the Commission in the FPA. *See N.Y. v. FERC*, 535 U.S. at 22 ("Moreover, we have described the precise reserved state powers language in [FPA section] 201(a) as a mere policy declaration that cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose." (quotation marks omitted)).

[450] *See Pac. Gas & Elec. Co.*, 461 U.S. at 205 ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."); *Monongahela Power Co.*, 40 FERC ¶ 61,256 at 61,861 ("[J]urisdiction over the capacity planning, determination of power needs, plant siting, 1icensing, construction, and the operations of coal-fired plants had been deliberately withheld from our control or responsibility . . . ."); *cf. Nw. Cent. Pipeline Corp.*, 489 U.S. at 522 ("Unless clear damage to federal goals would result, FERC's exercise of its authority [under the Natural Gas Act] must accommodate a State's regulation of production [of natural gas]."); *Piedmont Env't Council*, 558 F.3d at 310 ("The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities."); *Calpine Corp. v. PJM Interconnection*, 171 FERC ¶ 61,035 (Glick, Comm'r, dissenting at P 5).

and directly regulates only those practices.[451] These findings are not contested in the rehearing requests challenging the Commission's authority. As discussed in Order No. 1920 and above, Order No. 1920 is also not aimed at and does not regulate any area of reserved state authority, whether over electricity generation or otherwise, confirming that the rule is within the Commission's authority.[452] While it would be unlawful for the Commission to regulate within reserved state areas of authority, even as a means of accomplishing objectives within the Commission's statutorily granted authority,[453] a Commission regulation does not run afoul of FPA section 201(b) just because it affects,

[451] Order No. 1920, 187 FERC ¶ 61,068 at P 263 (noting that "no commenter contests" this point); *see id.* P 265-66; *EPSA*, 577 U.S. at 278 (construing the text of FPA section 206 regarding the Commission's "'affecting' jurisdiction" as limited to rules or practices that "directly affect" the rates within the Commission's jurisdiction); *NARUC*, 964 F.3d at 1186-87 (applying *EPSA*, considering whether the practice at issue meets the "directly affects" test, whether the Commission directly regulates state areas of authority, and whether the Commission action does not conflict with the FPA's core purposes); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 63 ("[B]ecause the orders' planning mandate is directed at ensuring the proper functioning of the interconnected grid spanning state lines, the mandate fits comfortably within Section 201(b)'s grant of jurisdiction over 'the transmission of electric energy in interstate commerce.'" (citation omitted)); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d at 481-82 (where economic impact of FERC regulation would likely cause States to construct new generation facilities, such state response was not the result of a "direct regulation" of generation facilities but the product of a state's response to changed incentives and "has little relevance").

[452] *See NARUC*, 964 F.3d at 1186-87 (finding that Commission order did not unlawfully regulate matters left to the States; "States remain equipped with every tool they possessed prior to Order No. 841 to manage their facilities and systems.").

[453] *See EPSA*, 577 U.S. at 279-80 (positing a hypothetical in which the Commission "issued a regulation compelling every consumer to buy a certain amount of electricity on the retail market" as a means of altering wholesale prices falling with the Commission's jurisdiction and explaining that this would be unlawful "because it specifies terms of sale at retail—which is a job for the States alone").

even substantially, a reserved area of state authority.[454] To the contrary, the rule is exactly the opposite: when the Commission regulates within the areas set forth for its authority in FPA sections 201 and 206 (here, practices directly affecting rates for interstate transmission of electricity) as part of "carrying out its charge to improve how that market runs . . . [FPA section 201(b)] imposes no bar" to such regulation, "no matter the effect" on areas of state authority.[455] *EPSA* is, therefore, fatal to the arguments asserting that Order No. 1920 is unlawful on the theory that, by regulating transmission planning processes and cost allocation, Order No. 1920 may affect state generation resource planning or other areas of state authority.

156. Furthermore, the rehearing requests disregard how Order No. 1920 ensures that Long-Term Regional Transmission Planning processes facilitate and respect the lawful authority of actors, including states, in areas such as generation resource planning, electricity production, and electricity demand. Factor Categories One, Two, and Three, in particular, require transmission providers to consider "(1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; [and] (3) state-approved integrated resource plans

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[454] *See id.* at 281 ("[A] FERC regulation does not run afoul of 824(b)'s proscription just because it affects—even substantially—the quantity or terms of retail sales."); *NARUC*, 964 F.3d at 1186-87; Order No. 1920, 187 FERC ¶ 61,068 at P 264; *see also id.* PP 265-266.

[455] *EPSA*, 577 U.S. at 281-82 (such effects are "of no legal consequence"); Order No. 1920, 187 FERC ¶ 61,068 at P 264; *see also id.* PP 265-66.

and expected supply obligations for load-serving entities."[456] Far from intruding on the authority of states in these domains, Order No. 1920 requires that in developing Long-Term Scenarios transmission providers account for that authority in Long-Term Regional Transmission Planning and, in fact, afford states *maximum* respect for that authority by assuming that these laws, regulations, integrated resource plans, and expected supply obligations will be fully met.[457] If anything, the Commission has adopted a conservative approach to ensure that Order No. 1920 is consistent with the structure of federalism set forth in the FPA.[458]

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[456] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

[457] *See id.* PP 417, 507. At the same time, the Commission in Order No. 1920 reasonably recognized that the first three categories of factors are not the only known determinants of transmission needs.

[458] FPA section 215(i)(3), 16 U.S.C. 824o(i)(3), and section 216, 16 U.S.C. 824p, which certain rehearing requests cite in passing, *see* Undersigned States Rehearing Request at 6, 11; Designated Retail Regulators Rehearing Request at 6-7, 13, 18-19, do not affect this conclusion. Neither provision limits the Commission's authority over transmission planning processes or cost allocation under the FPA. Rather, section 215(i)(3) establishes that "[n]othing in this section," relating to establishment of Electric Reliability Organizations, "shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard." The National Interest Electric Transmission Corridor process in section 216 affords the Commission, in certain circumstances, authority over siting of interstate electric transmission facilities; the siting of particular transmission facilities is not at issue in Order No. 1920. *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 254, 258.

### c. Order No. 1920 Does Not Require Unlawful Subsidization of State Policies

157. We also remain unpersuaded by arguments that Order No. 1920 exceeds the Commission's authority because it will allegedly intrude into state authority by requiring them to effectively subsidize the policies or generation resource mixes of other states.[459] Nothing in Order No. 1920 requires a state to subsidize the policies of other states.[460] In particular, and among other requirements to ensure such subsidization will not occur, Order No. 1920 mandates "consistent with long-established Commission and court precedent, that transmission customers within a transmission planning region need only pay costs that are 'roughly commensurate' with the benefits that transmission providers estimate they will receive from a regional transmission facility."[461]

158. No cost allocation method proposals have yet been submitted to the Commission in response to Order No. 1920, let alone approved, and application of any such hypothetical Commission-approved proposals to particular Long-Term Regional

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[459] *See* Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 14-15; Georgia Commission Rehearing Request at 5-6; Arizona Commission Rehearing Request at 11-12; Montana Commission Rehearing Request at 2-4; West Virginia Commission Rehearing Request at 2-4, 10-12.

[460] Order No. 1920, 187 FERC ¶ 61,068 at P 267; *see also, e.g.*, *id.* PP 232, 268-70, 280; *cf. id.* P 1419 ("[W]e reiterate that all cost allocation methods, including those resulting from a State Agreement Process, must allocate costs in a manner that is at least roughly commensurate with estimated benefits.").

[461] *Id.* P 267; *see id.* P 268 (discussing various requirements in Order No. 1920, including the beneficiary-pays cost allocation principle, that "provide robust assurance that the cost allocation methods ultimately proposed under the final rule will not result in improper cost subsidization."); *id.* P 280.

Transmission Facilities is even further in the future. As a result, disputes about the precise cost allocation method that transmission providers may file, the benefits associated with particular transmission facilities, or how the costs of those particular facilities may be allocated are necessarily theoretical and premature. Regardless, Order No. 1920's bedrock requirement that the cost allocation proposals that will eventually be filed must comply with the beneficiary-pays cost allocation principle is inconsistent with parties' claims that the Commission is unlawfully requiring consumers who do not benefit from Long-Term Regional Transmission Facilities to subsidize such facilities. This beneficiary-pays approach is a just and reasonable basis for allocating costs of regional transmission projects.[462] Indeed, courts and the Commission have explained that

[462] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 84; *see id.* at 85 (noting that the court had "repeatedly embraced" the "basic tenet" of beneficiary-pays cost allocation as a logical extension of the cost causation principle and that the Commission has "reasonably identified the lack of beneficiary-based cost allocation as a practice likely to result in rates that are not just and reasonable or are unduly discriminatory or preferential" (citing Order No. 1000, 136 FERC ¶ 61,051 at P 487); *Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 941 (8th Cir. 2020) ("[I]t is certain that to the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred. Because NPPD has greatly benefitted from Tri-State's facilities, it is likely that some of the costs have been caused by NPPD." (internal quotations and alterations omitted)); *ICC v. FERC I*, 576 F.3d at 476 ("Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred . . . ." (citations omitted)).

requiring that the costs imposed must be at least roughly commensurate to the benefits received[463] ensures that rates remain "just" by avoiding subsidization.[464]

159. Furthermore, the requests for rehearing arguing that Order No. 1920 intrudes on their authority by requiring such subsidization place too much weight on the broad premise that states have reserved authority over generation resource planning and electricity production within their own borders.[465] This, however, is a far cry from

[463] As discussed in greater detail below, Order No. 1920 recognized that Long-Term Regional Transmission Facilities are likely to provide a diverse array of benefits. The Commission specifically required that transmission providers consider seven economic and reliability benefits in Long-Term Regional Transmission Planning, but did not prohibit them from also considering public policy benefits. *See infra* Omission of Regional Cost Allocation Principle No. 6 and Ability to Allocate Costs by Type of Project section (reiterating the fundamental principle that costs will be allocated in a manner that is at least roughly commensurate with estimated benefits, ensuring that ratepayers will not pay for facilities from which they do not benefit).

[464] *El Paso Elec. Co. v. FERC*, 76 F.4th 352, 361-63 (5th Cir. 2023) ("The cost-causation principle, as understood by the courts and articulated in Order No. 1000, . . . ensure[s] that rates are 'just' . . . [by] prevent[ing] 'subsidization by ensuring that costs and benefits correspond to each other.'" (quoting Order No. 1000-A, 139 FERC ¶ 61,132 at P 578; citing *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d at 268; *Nat'l Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007))).

[465] *See, e.g.*, Undersigned States Rehearing Request at 10-13; Designated Retail Regulators Rehearing Request at 11-14; Montana Commission Rehearing Request at 2-4 (arguing that Order No. 1920 intrudes on state authority because "without a voluntary state agreement process, the Final Rule's regional cost allocation scheme ensures that nonconsenting states will be swept up in their neighbors' preferred policy projects"); Wyoming Commission Rehearing Request at 2-4 (similar); West Virginia Commission Rehearing Request at 3-4, 10-12 (similar); Arizona Commission Rehearing Request at 13 ("[S]tates without renewable resource policy objectives will be forced to absorb costs generated by the transmission of (often rurally sited) renewable energy." (emphasis omitted)); Georgia Commission Rehearing Request at 5-6; Utah Commission Rehearing Request at 6-7.

establishing that state authority over generation within that state's own borders also includes a right to be free from the incidental effects of policies of other states (e.g., as to generation planning) as those effects may manifest through interstate commerce in electricity. For example, Undersigned States and Designated Retail Regulators cite the federal/state division of authority set forth in the FPA, and argue that "[e]ach state has authority over the choice of which generating resources are maintained and constructed within its own jurisdiction."[466] However, they then recast this as a broader "right to choose the resources that best fit their public policies," a framing that omits the geographic limitation that states' reserved authority over such resources applies only to resources within their own jurisdiction.[467] As a consequence, they claim, it is "an over-reach into the traditional area of regulation reserved for the States" for their residents "to pay for infrastructure to support[ ] the public policies and resource mixes of other States, without demonstrable benefits to that load" as the costs of those policies manifest in interstate transmission facility cost allocations.[468]

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[466] Undersigned States Rehearing Request at 11-12; Designated Retail Regulators Rehearing Request at 13.

[467] Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 14.

[468] Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 14. This reference to "demonstrable benefits to load" appears to reflect the view that certain states may disagree with the choices of other states in terms of generation resource selection, particularly on the basis that "less-remote resources of any type might be less expensive, more reliable, and environmentally beneficial." Undersigned States Rehearing Request at 4-5; Designated Retail Regulators Rehearing Request at 4-5 (similar).

160. Neither statutory text in the FPA nor any of the precedent cited by the rehearing requests establishes that states' authority, when they participate in interstate commerce in electricity, includes a right to be free from the incidental extraterritorial effects of the policies of other states as they may manifest through such interstate commerce.[469] To the contrary, as the Supreme Court has recognized, "the production and transmission of energy is an activity particularly likely to affect more than one State."[470] The FPA is a congressional enactment authorizing the Commission to regulate in this area.[471]

161. In fact, the FPA was enacted in response to a Supreme Court decision holding that the Commerce Clause prevents states from regulating certain transactions between electric utilities located in other states—thereby creating the "*Attleboro* gap."[472]

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[469] No such generic right to avoid the extraterritorial effects of the policies of other states as they may manifest through interstate commerce exists under the Constitution. *See Nat'l Pork Producers Council v. Ross*, 598 U.S. 356, 371-74 (2023) (rejecting arguments, under the dormant Commerce Clause, "invoking . . . an 'almost per se' rule forbidding enforcement of state laws that have the 'practical effect of controlling commerce outside the State,' even when those laws do not purposely discriminate against out-of-state economic interests").

[470] *Ark. Elec. Co-op. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983) (explaining also that the effect of such production and transmission "on interstate commerce is often significant enough that uncontrolled regulation by the States can patently interfere with broader national interests"); *see* Order No. 1920, 187 FERC ¶ 61,068 at P 282 ("The nature of the interconnected transmission system is such that states naturally affect one another in pursuing policies available to them while exercising the authority reserved to them under FPA section 201.").

[471] *See* 16 U.S.C. 824(a), (b)(1), 824d, 824e.

[472] *EPSA*, 577 U.S. at 266 (citing *Pub. Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927)).

Congress responded by passing the FPA,[473] preventing the "creation of any regulatory 'no man's land.' Some entity must have jurisdiction to regulate each and every practice that takes place in the electricity markets."[474] *Attleboro* and Congress's enactment of the FPA thus reflect the authority vested in the Commission to regulate in these domains precisely because states are constitutionally incapable of doing so, including as to how the interaction of state policies may manifest in interstate commerce.[475] Moreover, the purported requirement that states must voluntarily agree to any cost allocation for interstate transmission facilities would run the risk of creating the sort of "regulatory void" that the FPA was designed to preclude. In particular, it would effectively assign to the states the regulatory responsibility for cost allocation of interstate transmission facilities (notwithstanding that this falls within an area Congress assigned to the Commission in the FPA), creating the possibility that this area goes entirely unregulated should states fail to reach agreement.[476] In other words, far from prohibiting any

[473] *Id.*

[474] *Id.* at 289 (citation omitted).

[475] *See Appalachian Power Co. v. Pub. Serv. Comm'n of W. Va.*, 812 F.2d 898, 905 (4th Cir. 1987) (enactment of the FPA reflects "the judgment embodied in the commerce clause that there are situations in which the broader perspective of federal authority is necessary"); *cf. id.* at 904 ("[S]tates are powerless to exert authority that potentially conflicts with FERC determinations regarding rates or agreements affecting rates.").

[476] Order No. 1920, 187 FERC ¶ 61,068 at P 1293 ("[I]f transmission providers were to rely solely on a State Agreement Process to determine the cost allocation for Long-Term Regional Transmission Facilities and that process fails to result in agreement, there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term

extraterritorial effects, the FPA's statutory standard puts the Commission in charge of regulating those effects pursuant to the just and reasonable standard, which includes the cost causation principle.

162. The argument that, particularly absent state agreement to cost allocation, Order No. 1920 exceeds the Commission's authority is also ahistorical when viewed in the regulatory context.[477] In Order No. 1000, the Commission required that transmission providers "devise methods for allocating the costs of certain new transmission facilities to those entities that benefit from them."[478] The D.C. Circuit held that this requirement fell within the Commission's statutory authority to regulate practices affecting rates[479] and otherwise rejected challenges to the Commission's authority to adopt these cost allocation reforms under FPA section 206.[480] In addition, Order No. 1000 also adopted

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Transmission Needs."); *see also infra* Obligation to File an Ex Ante Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section.

[477] The Supreme Court has observed that "[i]n our interconnected national marketplace, many (maybe most) state laws have the 'practical effect of controlling' extraterritorial behavior" such that application of an "extraterritoriality doctrine" to preclude such effects would lead to "strange places." *Nat'l Pork Producers Council*, 598 U.S. at 374-75 (citing examples and concluding that adopting this rule would "cast a shadow over laws long understood to represent valid exercises of the States' constitutionally reserved powers"); *id.* at 390 (noting that the Supreme Court has "recognized since *Gibbons* [*v. Ogden*], 9 Wheat 1, 22 U.S. 1 (1824), that virtually all state laws create ripple effects beyond their borders").

[478] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 81; *see id.* at 82-83 (discussing these reforms in more detail).

[479] *See id.* at 84.

[480] *See id.* at 84-87.

Cost Allocation Principle 1, requiring (like Order No. 1920) that the cost of transmission facilities be allocated to those that will benefit from those facilities in a manner at least roughly commensurate with the estimated benefits of that facility.[481] In doing so, the Commission neither required state agreement to *ex ante* cost allocation methods, nor that any such method ensure that costs be allocated based on whether a state agreed with the public policies of other states associated with the generating facilities connected to the relevant transmission facilities.[482] Order No. 1920's approach of requiring an Engagement Period directed toward state agreement on cost allocation, with an *ex ante* cost allocation backstop,[483] thus reflects an expansion of states' ability to participate in the development of regional cost allocation methods as compared to the status quo ante, while recognizing the bounds of state authority. And we take further steps in this order to ensure that states have a meaningful opportunity to inform both Long-Term Regional Transmission Planning and cost allocation for Long-Term Regional Transmission

[481] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 622; *see S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 85 ("The Commission therefore reasonably identified the lack of beneficiary-based cost allocation as a practice likely to result in rates that are not just and reasonable or are unduly discriminatory or preferential." (citing Order No. 1000, 136 FERC ¶ 61,051 at P 487)).

[482] *Cf.* Order No. 1000, 136 FERC ¶ 61,051 at P 685 (permitting, but not requiring, transmission providers to use different types of cost allocation methods for different types of transmission facilities, "such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements").

[483] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1291-1292.

Facilities, particularly with respect to the implementation and effect of state public policies.

163. Order No. 1920 regulates within, and only within, Commission authority, while ensuring that state policy choices in areas of reserved state authority are respected and effectuated. Order No. 1920 treats such choices evenhandedly and as antecedent to Long-Term Regional Transmission Planning, requiring transmission providers to consider those choices, among other factors, when they identify Long-Term Transmission Needs and (ultimately) Long-Term Regional Transmission Facilities.[484] Long-Term Regional Transmission Planning is, in turn, focused on evaluating the Long-Term Regional Transmission Facilities that will reliably and cost-effectively deliver the power needed to serve the load that is expected given these (and other) drivers of transmission needs.[485] As to cost allocation, transmission providers have flexibility to propose specific cost allocation methods for Long-Term Regional Transmission Facilities, but the prospect of unlawful subsidization of such a transmission facility by customers that do not benefit from it is foreclosed by the requirement that any such method must conform to the beneficiary-pays cost allocation requirement.[486] To be clear, that means that no

[484] *See supra* Requests to Omit One or More Categories of Factors section.

[485] *Id.*; *see also supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[486] Similarly, we find that Undersigned States and Designated Retail Regulators assertion that they may be required to pay for infrastructure "without demonstrable benefits to that load," Undersigned States Rehearing Request at 12-13; Designated Retail Regulators Rehearing Request at 14, is misplaced. Under the beneficiary-pays principle, costs are assigned to customers only to the extent that they receive demonstrable benefits

state or its customers will be required to pay for the costs of Long-Term Regional Transmission Facilities unless they benefit from those transmission facilities and in a manner that is at least roughly commensurate with those costs. This approach toward the interplay of federal and state regulation of electricity wholly comports with the jurisdictional lines drawn in the FPA.[487]

164. Contrast this with the rehearing requests challenging the Commission's authority under the FPA. By virtue of states' connection to the interstate transmission grid, consumers in those states participate in interstate commerce. However, certain parties seeking rehearing object to the potential consequences of that connection, particularly the amount that these ratepayers may be required to pay for the transmission facilities connecting to those resources. But where a ratepayer in one state benefits from a transmission facility, it is appropriate that they bear costs at least roughly commensurate with that benefit.[488]

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that are at least roughly commensurate with those costs.

[487] *See EPSA*, 577 U.S. at 282 ("considering 'the *target* at which a law *aims*'" in deciding whether FERC's wholesale market rule fell within its power to regulate wholesale sales (quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 385 (2015)); *cf. Hughes v. Talen Energy Mktg., LLC,* 578 U.S. 150, 165 (2016) (holding that states may not set retail rates, a power typically falling on the states' side of the FPA's jurisdictional line, 16 U.S.C. 824(b)(1), in a way that fails to "give effect" to a wholesale rate); *Oneok*, 575 U.S. at 385–86 (contrasting a state policy properly aimed at its field of jurisdiction with one aimed directly at the federal field).

[488] Indeed, a contrary rule would arguably be inconsistent with judicial precedent governing cost causation. *See, e.g.*, *El Paso Elec. Co.*, 76 F.4th at 360-63 (finding that the Commission impermissibly "prohibited the WestConnect region from imposing binding cost allocation on the non-jurisdictional utilities although they will 'cause,' in part, the costs of new grid improvements"); *id.* at 361-62 (explaining that it was of

165. For the reasons stated above and in Order No. 1920, we disagree with arguments that, under the FPA, the Commission's authority to regulate interstate transmission planning processes and cost allocation is limited as these rehearing requests claim. We find that the requirements of Order No. 1920 are within our authority over the "transmission of electric energy in interstate commerce," and particularly to ensure that practices affecting rates for such transmission are just and reasonable.[489]

### C. Major Questions Doctrine

#### 1. Requests for Rehearing

166. Several of the rehearing requests also invoke the "major questions" doctrine, particularly the Supreme Court's decision in *West Virginia v. EPA*,[490] in connection with their contention that Order No. 1920 exceeds the Commission's statutory authority.[491] Undersigned States and Designated Retail Regulators argue that Order No. 1920 involves a "major question" such that Order No. 1920 must be supported by clear congressional authorization because the Commission is attempting to supplant state generation planning

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fundamental legal importance that the non-jurisdictional utilities at issue were specifically and intentionally designated as beneficiaries, rather than incidental, unintended beneficiaries, such that they were impermissible "free riders" if not allocated an appropriate share of costs).

[489] 16 U.S.C. 824(b)(1), 824d(a), 824e(a).

[490] 597 U.S. 697.

[491] *See* Undersigned States Rehearing Request at 7, 14-17; Designated Retail Regulators Rehearing Request at 7, 15-19; Arizona Commission Rehearing Request at 2, 3-6 & n.8; Idaho Commission Rehearing Request at 2, 6-7; Utah Commission Rehearing Request at 1, 7-8; Ohio Commission Federal Advocate Rehearing Request at 20.

authority in favor of promoting distantly located renewable energy.[492] They assert that *West Virginia* supports concluding that Order No. 1920 implicates the major questions doctrine.[493] Undersigned States and Designated Retail Regulators also point to the claimed economic consequences of Order No. 1920, citing alleged costs in the hundreds of billions or trillions of dollars; the breadth of the transmission grid; and the importance of electricity in everyday life.[494] They argue that Order No. 1920 is "blatantly preferential," will not ensure just and reasonable rates, and that attempting to influence the generation resource mix exceeds both the Commission's expertise and the scope of the FPA as a consumer-protection statute geared toward ensuring such just and reasonable rates.[495]

167. Likewise, Arizona Commission argues that the Commission has "implemented a nationwide scheme, foisted on all 50 states, to adopt energy generation modes to *its*

[492] Undersigned States Rehearing Request at 14-15; Designated Retail Regulators Rehearing Request at 15-16; *see also id.* at 17-18 ("[T]here is no clear delegated authority allowing FERC to determine what type of generating resources should be transmitted from where in the United States.").

[493] Undersigned States Rehearing Request at 14-15 (also asserting that this is a major question because "it implicates a unique and complex jurisdictional divide between state and federal regulatory authority" (citing *Ala. Ass'n of Realtors v. HHS*, 594 U.S. 758, 764 (2021); *EPSA*, 577 U.S. at 264-65)); Designated Retail Regulators Rehearing Request at 17.

[494] Undersigned States Rehearing Request at 15; Designated Retail Regulators Rehearing Request at 16-17.

[495] Undersigned States Rehearing Request at 16-17; Designated Retail Regulators Rehearing Request at 16-17, 18-19.

liking" even though "nothing in th[e FPA] authorizes the adoption of the Biden Administration's renewable energy policy goals."[496] Arizona Commission and Utah Commission assert that in *West Virginia* the Supreme Court stated that it is highly unlikely that Congress would leave to agency discretion how much coal-based generation there should be over the coming decades, and assert that major policy changes must occur pursuant to an express statement of Congress.[497] Arizona Commission argues that commenters have observed the breadth and consequences of Order No. 1920[498] and cites a characterization of the Commission's approach as controversial,[499] asserts that the FPA is a consumer protection statute,[500] and states that Congress has not enacted the "Green New Deal."[501] Utah Commission contends that "transitioning the grid away from fossil-fueled generation and toward renewable resources" is a major question, pointing to its social and political context and economic consequences.[502]

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[496] Arizona Commission Rehearing Request at 4-6.

[497] *Id.* at 5-6; *see also id.* at 3-4 (arguing that Congress does not use oblique or elliptical language to empower fundamental changes to a statutory scheme); Utah Commission Rehearing Request at 7-8.

[498] *See* Arizona Commission Rehearing Request at 6; *cf. id.* at 16 (citing the cost of achieving net-zero on the transmission grid).

[499] *See id.* at 4-5.

[500] *See id.* at 20.

[501] *See id.* at 5.

[502] Utah Commission Rehearing Request at 8 & n.17 (arguing that Order No. 1920 "patently dictates outcomes and cost allocation and does so to discriminate and favor the policy preferences of certain preferred stakeholders"; citing Commissioner Christie's

168. In arguing that Order No. 1920 involves a major question, Idaho Commission points to statements in the concurrence to Order No. 1920 that the nation's energy grid is at a crossroads, with "'consequential action' . . . emphatically warranted" and "proselytiz[ing] for states to join it in building an 'electric transmission grid for the 21st century.'"[503] It contends that the Commission has "gone to great lengths to enact a sweeping policy agenda, in the absence of congressional authority, that infringes on states' authority, and impermissibly attempts to expand the Commission's jurisdiction under the FPA, in violation of the major questions doctrine."[504]

169. Ohio Commission Federal Advocate argues, citing *West Virginia*, that the Commission has not identified a clear congressional authorization to "use its power under the FPA to facilitate federal, state, Tribal, local, and corporate policies, including decarbonization and electrification policies, under the guise of building a robust transmission system."[505] It argues that the Commission lacks this authority.[506]

170. SERTP Sponsors bring several requests for clarification of Order No. 1920, which we summarize and address in detail below. Focusing on the "respect afforded to state-

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dissent claiming that Order No. 1920 is intended to cost consumers trillions of dollars).

[503] Idaho Commission Rehearing Request at 6 (quoting Order No. 1920, 187 FERC ¶ 61,068 (Phillips & Clements Comm'rs, concurring at PP 34-35)).

[504] *Id.* at 6-7.

[505] Ohio Commission Federal Advocate Rehearing Request at 20.

[506] *Id.*

approved IRPs and LSE supply obligations," SERTP Sponsors state that, absent certain of those clarifications, "particularly [in] Sections II.A.1 and II.C.3" of their argument, Order No. 1920 could encroach on state jurisdiction.[507] They particularly contend that if these clarifications are not granted "Order No. 1920 would be seeking to influence the makeup of the nation's energy policy and generation mix, which would constitute a 'major question,' given the vast economic consequences that would result from an exercise of such authority."[508]

### 2. Commission Determination

171. We continue to find that Order No. 1920 does not implicate the major questions doctrine. As the summary above reflects, the rehearing requests provide little to no discussion of the scope of the Commission's authority under the FPA or the statutory context and, as discussed in the preceding sections, they misinterpret Order No. 1920 itself.[509] The Supreme Court has described the major questions doctrine as applicable only in "extraordinary cases," which it has identified through a detailed analysis of the

[507] SERTP Sponsors Rehearing Request at 37-41; *see also id.* at 41-45.

[508] *Id.* at 39-40 (arguing that "the application or implementation of Order No. 1920 in a manner that would undercut or conflict with state-regulated IRPs and resource adequacy decisions would transform the regulatory paradigm from an electric system expansion process driven by state-regulated resource assumptions made in state-regulated IRPs to one driven by FERC-regulated resource assumptions made in the FERC-regulated LTRTP processes," exceeding the scope of the Commission's expertise and previous regulation of "practices affecting rates").

[509] *See supra* Federal/State Division of Authority section.

statutory context and agency action at issue.[510] Specifically, that doctrine comes into play where, despite a "colorable textual basis" for the agency's claim of authority, the agency action was so extravagant when viewed in light of the statutory context that it was unlikely that Congress would have afforded this claimed authority to the agency, and particularly would not have done so in an oblique or subtle way.[511] As a rule, Congress does not "hide 'elephants in mouseholes.'"[512]

172. In *West Virginia*, the Supreme Court held that EPA claimed a "newfound," "transformative," "extravagant," and "unheralded"[513] authority to "substantially restructure the American energy market" by devising emission limitations that were based on EPA's judgment of how much coal-fired electricity generation should be in the overall mix of electricity generation.[514] The Supreme Court concluded that this authority

[510] *See West Virginia*, 597 U.S. at 721.

[511] *Id.* at 722-23; *see also id.* at 721.

[512] *See id.* at 746 (Gorsuch, J., concurring) (quoting *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001)); *see also Nat'l Fed'n of Indep. Bus. v. Dep't of Lab., Occupational Safety & Health Admin.,* 595 U.S. 109, 125 (2022) (Gorsuch, J., concurring).

[513] *West Virginia*, 597 U.S. at 724; *see also Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 323-24 (2014) (*UARG*) (rejecting EPA's "enormous and transformative expansion in EPA's regulatory authority" in "discover[ing] in a long-extant statute an unheralded power" to require certain permits for greenhouse gas emissions).

[514] *West Virginia*, 597 U.S. at 721, 724-25; *see also Nat'l Fed'n of Indep. Bus.*, 595 U.S. at 117 ("The Secretary has ordered 84 million Americans to either obtain a COVID–19 vaccine or undergo weekly medical testing at their own expense. This is no everyday exercise of federal power." (citation omitted)); *UARG*, 573 U.S. at 321-22 (explaining that EPA itself acknowledged the "calamitous consequences of interpreting the [Clean Air] Act in that way," thereby rendering the relevant provisions multiple

swept far beyond the ordinary understanding of EPA's purview, inserting the agency into areas into which it lacked technical expertise and in which it was required to make "a very different kind of policy judgment."[515] EPA did so against the backdrop of the significant policy questions involved that would ordinarily be addressed by Congress.[516] In fact, the Supreme Court recognized that EPA's newly claimed authority enabled it to enact a program addressing the dangers posed by greenhouse gas emissions even though

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orders of magnitude more burdensome and expensive); *id.* at 324 ("[W]e confront a singular situation: an agency laying claim to extravagant statutory power over the national economy while at the same time strenuously asserting that the authority claimed would render the statute 'unrecognizable to the Congress that designed' it." (citation omitted)); *Food & Drug Admin. v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 159-60 (2000) (explaining that "[t]his is hardly an ordinary case" given that the FDA was now purporting to have authority that would allow it to outright ban tobacco products, notwithstanding the unique place such products have in American history and the existing regulatory scheme adopted by Congress).

[515] *West Virginia*, 597 U.S. at 728-29 (noting that, in this context, EPA was required to make judgments as to the reliability of the energy grid and the effects of its action on energy prices, such that EPA's exercise of authority required "technical and policy expertise *not* traditionally needed in EPA regulatory development" (quotation marks omitted)); *see also Nat'l Fed'n of Indep. Bus.*, 595 U.S. at 118 ("[N]o provision of the Act addresses public health more generally, which falls outside of OSHA's sphere of expertise."); *King v. Burwell*, 576 U.S. 473, 485-86 (2015) (declining to defer to the Internal Revenue Service (IRS) interpretation of the Affordable Care Act's guarantee of tax credits for health insurance purchases, noting that that decisions about "health insurance policy" fell beyond the IRS's zone of "expertise," making it "especially unlikely that Congress would have delegated th[e] decision" over tax credits "to the *IRS*.").

[516] *West Virginia*, 597 U.S. at 729-30; *see also King*, 576 U.S. at 485-86 (noting that the tax credits at issue "involv[e] billions of dollars in spending each year and affect[ ] the price of health insurance for millions of people," the Court deemed their provision "a question of deep economic and political significance" that Congress would not have implicitly delegated to the agency (quotation marks omitted)).

Congress had considered (but rejected) legislative proposals to create such programs.[517] Thus, in *West Virginia*, the Supreme Court confronted an EPA assertion of authority that it concluded was elephantine—surprising not just in scope, but also in character vis-à-vis EPA's ordinary regulatory role.

173. The Supreme Court concluded that EPA purported to find that authority in a statutory mousehole: the "ancillary," "backwater," "gap-filler" authority in section 111(d) of the Clean Air Act, under which it was to identify the "best system of emission reduction" for existing stationary sources of air pollutants.[518] Reflecting the ancillary nature of this provision, the Supreme Court noted that EPA had only used it a handful of times over more than four decades,[519] and in doing so had uniformly based its regulatory approach on identifying systems that would reduce pollution by causing the regulated source to operate more cleanly.[520] As a result, according to the Supreme Court, EPA's

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[517] *West Virginia*, 597 U.S. at 731-32 ("Congress, however, has consistently rejected proposals to amend the Clean Air Act to create such a program."); *see also Brown & Williamson*, 529 U.S. at 160 (adopting FDA's statutory interpretation required ignoring "the plain implication of Congress' subsequent tobacco-specific legislation"); *id.* at 142-58.

[518] *West Virginia*, 597 U.S. at 709-710 (noting that the "thrust of Section 111 focuses on emissions limits for *new* and *modified* sources" rather than the existing sources that EPA was regulating under the challenged rule); *id.* at 730.

[519] *Id.* at 710-11 ("It was thus only a slight overstatement for one of the architects of the 1990 amendments to the Clean Air Act to refer to Section 111(d) as an 'obscure, never-used section of the law.'" (citation omitted)).

[520] *Id.* at 725-26 (citing EPA's view, in its inaugural rulemaking under this provision, that Congress in this provision intended a technology-based approach); *see also Nat'l Fed'n of Indep. Bus.*, 595 U.S. at 118-19 ("It is telling that OSHA, in its half century of existence, has never before adopted a broad public health regulation of this

claim that it had authority to base emission limitations on its policy judgment regarding the appropriate generation resource mix "was not only unprecedented; it also effected a fundamental revision of the statute, changing it from [one sort of] scheme of . . . regulation into an entirely different kind."[521] The Supreme Court held that, to justify this power, EPA offered only a "vague statutory grant" supported by such an expansive, acontextual reading of the "definitional possibilities" of the word "system" that accepting this construction would have rendered the statutory text an "empty vessel."[522]

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kind . . . . [A] vaccine mandate is strikingly unlike the workplace regulations that OSHA has typically imposed."); *Brown & Williamson*, 529 U.S. at 144 (noting FDA's "consistent and repeated statements" that it lacked jurisdiction to regulate tobacco products).

[521] *West Virginia*, 597 U.S. at 728 (quotation marks omitted); *see also Nat'l Fed'n of Indep. Bus.*, 595 U.S. at 117-18 ("The Act empowers the Secretary to set workplace safety standards, not broad public health measures."); *UARG*, 573 U.S. at 322 (explaining that EPA itself recognized that the results of its statutory interpretation "would be so 'contrary to congressional intent,' and would so 'severely undermine what Congress sought to accomplish,' that they necessitated as much as a 1,000–fold increase in the permitting thresholds set forth in the statute"); *id.* at 322-23 (explaining how a "brief review of the relevant statutory provisions leaves no doubt that the PSD program and Title V are designed to apply to, and cannot rationally be extended beyond, a relative handful of large sources capable of shouldering heavy substantive and procedural burdens"); *MCI Telecomms. Corp. v. Am. Tel. & Telegraph Co.*, 512 U.S. 218, 234 (1994) ("[FCC's statutory interpretation] is effectively the introduction of a whole new regime of regulation (or of free-market competition), which may well be a better regime but is not the one that Congress established."); *cf. Brown & Williamson*, 529 U.S. at 156 ("Under these circumstances, it is clear that Congress' tobacco-specific legislation has effectively ratified the FDA's previous position that it lacks jurisdiction to regulate tobacco.").

[522] *West Virginia*, 597 U.S. at 732; *see also Brown & Williamson*, 529 U.S. at 160 (explaining that FDA's statutory interpretation required adopting "an extremely strained understanding of 'safety' as it is used throughout the Act" even though the concept is "central to the [Act's] regulatory scheme"); *MCI*, 512 U.S. at 229-34 (rejecting agency interpretation concluding that a statutory provision authorizing the FCC to "modify" the

174. *West Virginia* thus reflects the sort of "extraordinary case" meriting application of the major questions doctrine and illustrating the factors relevant to that inquiry. Moreover, *West Virginia* and other cases in this area reflect that application of that doctrine does not boil down to a facile examination, divorced from the statutory context, of the agency action at issue. The major questions doctrine does not provide, for example, that courts should find that an agency action requires express Congressional authorization based simply on the economic consequences of that action, the fact that the agency is addressing a significant problem, or the sector of industry that the agency is regulating. As the Fourth Circuit recently explained, while the "doctrine applies only when the question at issue—*i.e.*, the authority the agency is claimed to have—is a major one," that is a necessary, not a sufficient, condition triggering the doctrine's application.[523] "The [Supreme] Court has highlighted several other [relevant] hallmarks," such as (1) whether the statute's "structure indicates that Congress did not mean to regulate the issue in the way claimed,"[524] (2) whether a "'distinct regulatory scheme' [is] already in place to deal with the issue which would conflict with the agency's newly asserted authority,"[525] (3) where the agency has "fail[ed] to invoke the[] [asserted

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provisions of 47 U.S.C. 203 authorized the agency to make "radical or fundamental changes to the statutory requirements").

[523] *N.C. Coastal Fisheries Reform Grp. v. Capt. Gaston LLC*, 76 F.4th 291, 296-97 (4th Cir. 2023).

[524] *Id*.

[525] *Id*. (quoting *Brown & Williamson*, 529 U.S. at 143-46).

powers] previously," (4) where the "asserted authority falls outside the agency's traditional expertise," and (5) where the "asserted authority . . . is found in an 'ancillary provision.'"[526] As discussed below, none of these "hallmarks" is present here.

175. We continue to conclude that the major questions doctrine does not apply to Order No. 1920.[527] The Commission's authority under FPA section 206 is no statutory "mousehole." Far from being an "ancillary," "back-water," or "gap-filler" provision as the court referenced in *West Virginia*, FPA section 206 sets forth core Commission regulatory authority to remedy unjust and unreasonable rates, and practices affecting rates, for the transmission of electric energy in interstate commerce.[528] As discussed above, the Commission's action in Order No. 1920 falls well within the ordinary understanding of its statutory authority under this provision, as it is regulating practices directly affecting such rates,[529] such that Order No. 1920 does not involve converting the

[526] *Id*. (quoting *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. at 468).

[527] Order No. 1920, 187 FERC ¶ 61,068 at PP 275-279.

[528] 16 U.S.C. 824e(a); *see S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56 (explaining that the Commission's authority under FPA section 206 is "broadly stated and the only question is what limits are fairly implied"; this provision is not a "subtle device"); *id.* at 55 ("The text does not define 'practice,' although use of the word 'any' amplifies the breadth of the delegation to the Commission."); *cf. N.Y. v. FERC*, 535 U.S. at 15 (upholding Order No. 888, noting that the Supreme Court has "construed broadly" the Commission's jurisdiction under FPA section 201).

[529] *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (discussing the application of *EPSA* and related precedent to Order No. 1920 as confirming that the Commission is acting within its authority)

authority set forth to regulate such practices into a new kind of regulatory scheme.[530] By the same token, since it is based on this core statutory authority, Order No. 1920 also does not involve invoking definitional possibilities to stretch a statutory term or phrase (e.g., "system" in *West Virginia*) to its limits, thereby stripping the relevant term of meaning.

176. Also, unlike the provision at issue in *West Virginia*, FPA section 206 is not a rarely used provision; the Commission has acted under this authority countless times, including in significant rulemakings. This includes the Commission's landmark Order No. 888, in which the Commission addressed fundamental shifts in the landscape of the electric industry by requiring functional unbundling of wholesale generation and transmission services and imposing a similar open access requirement on unbundled retail transmission in interstate commerce,[531] as well as oversight of those processes and cost allocation via more targeted FPA section 206 complaints and Commission-initiated FPA section 206 proceedings.[532] The Supreme Court upheld Order No. 888 order,

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[530] *See EPSA*, 577 U.S. at 290 ("ensur[ing] effective transmission of electric power" is one of the "core objects" of the FPA); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 57.

[531] *See N.Y. v. FERC*, 535 U.S. at 11, 17.

[532] *See, e.g.*, *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 15 (D.C. Cir. 2021) (denying petitions for review of Commission order, under FPA section 206, regarding cost allocation for the Artificial Island Project); *Coal. of MISO Transmission Customers v. Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,099, 61,770 (2020) (denying complaint, under FPA section 206, challenging MISO's location-based cost allocation method for Baseline Reliability Projects); *City Utilities of Springfield, Mo. v. Sw. Power Pool, Inc.*, 168 FERC ¶ 61,085, 61,467 (2019) (denying complaint, under FPA section 206, asserting that SPP's administration of the unintended consequences

underscoring the breadth of the Commission's authority under FPA section 206. The Commission's exercise of this authority in the field of transmission planning processes and cost allocation is, itself, far from unprecedented considering the Commission's issuance of Order Nos. 890 and 1000, upon which Order No. 1920 now builds.[533] In Order No. 890, the Commission required—among other things—that public utility transmission providers' local transmission planning processes satisfy nine transmission planning principles to ensure that transmission planning processes were just and reasonable and not unduly discriminatory and preferential.[534] The Commission's next step, Order No. 1000, sought to further ensure that transmission planning and cost

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review process for SPP's allocation of the costs of transmission facilities was unjust, unreasonable, unduly discriminatory, or preferential); *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,058 (2016) (granting in part and denying in part a complaint under FPA section 206 requesting that the Commission reform the interregional transmission planning process of the Joint Operating Agreement between MISO and PJM); *Monongahela Power Co.*, 156 FERC ¶ 61,134 (2016) (instituting a proceeding under FPA section 206 to determine whether PJM transmission owners are complying with their Order No. 890 transmission planning obligations), *order accepting in part proposed tariff revisions and requiring tariff revisions*, 162 FERC ¶ 61,129 (2018).

[533] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 14-19, 47-48, 255; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 58 ("Commission-mandated transmission planning is not new. [Order No. 1000] builds on Order No. 890's requirements in light of changed circumstances and is simply the next step in a series of related reforms that began no later than Order No. 888." (citation omitted)).

[534] *See* Order No. 890, 118 FERC ¶ 61,119 at PP 418-601 (requiring, among other things, that local transmission planning processes satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects); Order No. 1920, 187 FERC ¶ 61,068 at PP 14, 277.

allocation requirements embodied in the *pro forma* OATT could facilitate the development of more efficient or cost-effective regional transmission facilities.[535] Order No. 1920 is a continuation of these prior efforts to ensure that transmission planning and cost allocation processes support the reliable and cost-effective operation of the transmission grid, by addressing identified deficiencies in those processes that render Commission-jurisdictional rates unjust and unreasonable.

177. Turning to the agency action at issue, Order No. 1920 is not an "elephant": while it addresses a significant problem, it does so through an improvement of the already existing Commission-jurisdictional regional transmission planning and cost allocation processes, building on and consistent with the Commission's exercise of authority in past actions,[536] and is not aimed at areas of reserved state authority. Rehearing requests arguing to the contrary—and particularly those claiming that the Commission is attempting to control or influence the resource mix or install itself as a national integrated resource planner—are based on mischaracterizations or misunderstandings of Order No.

[535] Order No. 1000, 136 FERC ¶ 61,051 at PP 11-12, 42-44; Order No. 1000-A, 139 FERC ¶ 61,132 at PP 3-6; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 16 ("The reforms in Order No. 1000 included: (1) regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost allocation, including a set of principles for each category of cost allocation; and (5) interregional transmission coordination. The reforms focused on the process by which transmission providers engage in regional transmission planning and the associated cost allocation rather than on the outcomes of the process.").

[536] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 278 (describing the rule as implementing "incremental process improvements").

1920, as discussed above.[537] Order No. 1920 is well within the Commission's ordinary remit and technical expertise of regulating practices affecting interstate transmission rates, unlike the cases discussed above which involved agency forays into areas well beyond their ordinary purview, such as EPA regulating the generation resource mix, Occupational Safety and Health Administration (OSHA) regulating the general public health, or the IRS addressing health insurance policy. Nor is this an instance in which the Commission has acted against a backdrop of contrary congressional action.[538]

178. Moreover, the Commission in Order No. 1920 acted in a fundamentally *responsive* capacity to require more effective transmission planning processes and cost allocation to ensure cost-effective and reliable Long-Term Regional Transmission Planning in light of preexisting forces beyond the Commission's control that give rise to transmission needs.[539] This stands in contrast to cases in which the Supreme Court has applied the major questions doctrine, which involved agency actions that, in themselves, affirmatively and proactively caused the transformative consequences that the Court

[537] *See supra* Federal/State Division of Authority section.

[538] Arguments to the contrary suggesting, for example, that the Commission is attempting to implement the "Green New Deal," rest on the incorrect premise that the Commission is attempting to preferentially favor renewable resources or influence the generation mix. Moreover, even the references cited in the rehearing requests describe the "Green New Deal" as a broad set of goals aimed at achieving net zero carbon emissions, without specific policies, rather than a specific proposal to enact the sort of transmission planning process and cost allocation reforms at issue in Order No. 1920. *See, e.g.*, Arizona Commission Rehearing Request at 4-5.

[539] *See supra* Federal/State Division of Authority section (noting that these forces would continue to exist, driving transmission needs, even absent Commission action).

identified as demonstrative of extravagant exercises of agency power.[540] For similar reasons, it is incorrect to ascribe to Order No. 1920, which aims to ensure that Long-Term Transmission Needs are met more efficiently and cost-effectively, the economic consequences associated with the construction of new transmission infrastructure, as the need for this infrastructure would still exist independent of Order No. 1920.[541]

179. In particular, arguments asserting that Order No. 1920 will impose "billions or trillions of dollars in transmission cost[s]"[542] claims that attempt to link the transmission

[540] *See, e.g.*, *West Virginia*, 597 U.S. at 721, 724-25 (addressing EPA rule seeking to "substantially restructure the American energy market"); *Nat'l Fed'n of Indep. Bus.*, 595 U.S. at 117 (addressing agency rule requiring vaccination or medical testing); *UARG*, 573 U.S. at 321-22 (addressing agency change in statutory interpretation subjecting millions of sources to permitting requirements).

[541] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 278 ("The incremental process improvements required by the final rule, however, do not fundamentally change the economic or political stakes of ensuring that Commission-jurisdictional rates remain just and reasonable."); *id.* PP 92-93; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 51 (noting the expense associated with construction of transmission infrastructure at the time of the promulgation of Order No. 1000). No case applying the major questions doctrine has done so solely based on the economic consequences of the agency action at issue or suggested that agencies are not empowered to address significant problems falling within their general grants of statutory authority. *Cf., e.g.*, *N.Y. v. FERC*, 535 U.S. at 11, 17 (affirming Commission order adopting reforms restructuring electricity markets); *Flyers Rts. Educ. Fund, Inc. v. U. S. Dep't of Transp.*, 810 F. App'x 1, 3 (D.C. Cir. 2020) (explaining that *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009) "permits, but does not require, an agency to act incrementally"); *WildEarth Guardians v. EPA*, 751 F.3d 649, 655-56 (D.C. Cir. 2014) (summarizing *Defs. of Wildlife v. Gutierrez*, 532 F.3d 913 (D.C. Cir. 2008), upholding a decision to focus on a comprehensive approach). Creating such a rule would be inconsistent with the Supreme Court's discussion of the history of the major questions doctrine reflecting its application only in extraordinary cases, and then only upon a detailed consideration of the statutory context. *See West Virginia*, 597 U.S. at 721.

[542] Undersigned States Rehearing Request at 15; *see* Designated Retail Regulators

costs of achieving a "net zero" carbon emission policy as "caused by Order No. 1920"[543] are not supported by the record and, instead, depend entirely on an unfounded logical leap. These arguments incorrectly portray the consequences of decisions made by other actors,[544] which represent preexisting and independent forces driving transmission needs that are outside of the Commission's control,[545] as attributable to Order No. 1920. As noted above, such arguments fundamentally reverse cause and effect by mischaracterizing Order No. 1920's process-focused requirements that transmission providers adequately *plan* for these drivers of Long-Term Transmission Needs—which requirements do not seek to achieve any substantive outcome or direct the construction of any particular transmission facilities—as *causing* these transmission needs.[546] This has no basis in fact. The drivers of these transmission needs (including those that flow from the policy decisions of actors lawfully entitled to make such choices) and the costs associated with building transmission infrastructure to meet such needs will exist

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Rehearing Request at 15-16.

[543] Arizona Commission Rehearing Request at 16.

[544] In particular, Order No. 1920 is neutral on the policy choices that may drive certain of these decisions, including whether "net zero" is an appropriate policy goal; these questions are not for the Commission to resolve.

[545] *See supra* Order No. 1920 Does Not Attempt to Control the Generation Mix or Intrude in Areas of State Authority section (explaining that Order No. 1920 is resource neutral, treating these exogenous forces that drive Long-Term Transmission Needs as inputs to Long-Term Regional Transmission Planning).

[546] *See supra* Order No. 1920 Does Not Attempt to Control the Generation Mix or Intrude in Areas of State Authority section.

independent of Order No. 1920's requirements. Indeed, because a major focus of Order No. 1920 is ensuring that more efficient or cost-effective transmission facilities are evaluated and selected, not only would these needs still exist absent the Commission's action but we expect that meeting these needs would impose *higher* costs on ratepayers.

180. We therefore continue to conclude that Order No. 1920 is not a transformative exercise of Commission authority, whether in magnitude or character, and FPA section 206 is not a surprising basis for the Commission's action, meaning that the major questions doctrine does not apply here.[547] The Supreme Court's decision in *EPSA* and D.C. Circuit decisions in *California Independent System Operator v. FERC*[548] and *South Carolina Public Service Authority v. FERC* further confirm the inapplicability of the major questions doctrine to Order No. 1920. Each of those cases addressed the scope of the Commission's authority under FPA section 206 over "practice[s] . . . affecting" rates, the same grant of statutory authority supporting issuance of Order No. 1920, and are thus of particular significance here.[549]

181. In *EPSA* and *CAISO*, the Courts' statutory construction limiting the Commission to regulating practices "directly affecting" rates was motivated by the same concern animating the major questions doctrine: effectuating congressional intent by ensuring that

[547] Order No. 1920, 187 FERC ¶ 61,068 at PP 278-279.

[548] 372 F.3d 395 (D.C. Cir. 2004) (*CAISO*).

[549] *See EPSA*, 577 U.S. at 277-78; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56-57; *CAISO*, 732 F.3d at 399-404.

the Commission's exercise of this authority was reasonably constrained by more than the definitional possibilities as to what constitutes a "practice . . . affecting" rates.[550] *South Carolina Public Service Authority v. FERC* considered the scope of this authority as applied to the same context presented here, transmission planning and cost allocation processes, in reviewing the highly similar Order No. 1000. The court held that "[r]eforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities is not the kind of interpretive 'leap' that concerned the court in *CAISO* but rather involves a core reason underlying Congress' instruction in [FPA] Section 206."[551] It likewise distinguished *MCI*—one of the cases the Supreme Court in *West Virginia* discussed as part of the lineage of the major questions doctrine—holding that FPA section 206 "cannot be fairly viewed as the type of 'subtle device' at issue" in that case.[552]

[550] *See EPSA*, 577 U.S. at 277-78 (adopting the "directly affecting" construction of FPA section 206(a) because "[t]aken for all it is worth, that statutory grant could extend FERC's power to some surprising places" given that markets in all of electricity's inputs might affect the supply of power and "markets in just about everything" might affect load-serving entities' demand); *CAISO*, 372 F.3d at 400 (explaining that ambiguity, in statutory construction, is not a creature of definitional possibilities but of statutory context); *id.* at 401 (rejecting the argument that there is an "infinitude of acceptable definitions for what constitutes a 'practice' to give [the Commission] the authority to regulate anything done by or connected with a regulated utility, as any act or aspect of such an entity's corporate existence could affect, in some sense, the rates").

[551] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 57.

[552] *Id.* at 56.

182. Thus, *EPSA* and *CAISO* reflect that the Supreme Court and the D.C. Circuit already have construed the statutory grant of authority to the Commission over practices affecting rates in FPA section 206 as imposing guardrails to ensure consistency with congressional intent and to avoid the use of this authority in ways that would implicate the major questions doctrine. *South Carolina Public Service Authority v. FERC*, in turn, applied these guardrails in the same context as Order No. 1920 and found that the Commission was acting within its statutory authority to address "a core reason underlying Congress' instruction in [FPA] Section 206."[553] Particularly given the major questions doctrine's focus on discerning congressional intent as to the scope of a legislative delegation,[554] these cases further support our conclusion (in addition to the discussion already set forth) that the major questions doctrine does not require enhanced skepticism of Order No. 1920.[555]

183. We are, therefore, unpersuaded by arguments that the major questions doctrine should apply to Order No. 1920. Claims that Order No. 1920 presents a major question because the Commission has overstepped the jurisdictional boundaries set forth in the FPA and intruded into areas of state authority[556] are mistaken because the Commission

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[553] *Id.* at 57.

[554] *See West Virginia*, 597 U.S. at 721-23.

[555] *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (explaining, as discussed in Order No. 1920 and not disputed on rehearing, that Order No. 1920 is consistent with the Supreme Court's decision in *EPSA*).

[556] *See* Undersigned States Rehearing Request at 14-15 (citing *Ala. Ass'n of*

has acted well within its authority to regulate practices affecting interstate transmission rates, honoring the jurisdictional divide set forth by Congress in the FPA.[557] Arguments that the Commission is misusing the FPA to enact preferential policies[558] are misplaced for the same reasons. As already discussed, arguments invoking the purported economic consequences of Order No. 1920[559] misattribute the costs of constructing transmission

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*Realtors v. HHS*, 594 U.S. at 764 (finding that one consideration favoring application of the major questions doctrine was that the agency action "intrudes into an area that is the particular domain of state law: the landlord-tenant relationship")); *id.* at 16 (arguing that the Commission was attempting to determine "what resources should be powering the grid twenty years into the future"); Designated Retail Regulators Rehearing Request at 15-19 (similar); Arizona Commission Rehearing Request at 5-6; Utah Commission Rehearing Request at 7-8; *cf.* Ohio Commission Federal Advocate Rehearing Request at 20 ("FERC points to no 'clear congressional authorization' for it to use its power under the FPA to facilitate federal, state, Tribal, local, and corporate policies . . . .").

[557] *See supra* Federal/State Division of Authority section; Order No. 1920, 187 FERC ¶ 61,068 at PP 263-267. We also reiterate, in response to arguments that the Supreme Court in *West Virginia* found it "'highly unlikely that Congress would leave to agency discretion the decision of how much . . . generation there should be over the coming decades' on a resource-by-resource basis," Undersigned States Rehearing Request at 15 (quoting *West Virginia*, 597 U.S. at 729; also citing "the breadth of the transmission grid [and] the importance of electricity in everyday life"), that "the Court did not determine that energy policy and the mix of generation resources are *in every instance* a major question." Order No. 1920, 187 FERC ¶ 61,068 at P 276; *see also id.* PP 277-278. In any event, Order No. 1920 still would not implicate the major questions doctrine because it is not aimed at this end.

[558] *See* Undersigned States Rehearing Request at 16-17; Designated Retail Regulators Rehearing Request at 16-17; Arizona Commission Rehearing Request at 3 n.2, 4, 20.

[559] *See* Undersigned States Rehearing Request at 14-15; Designated Retail Regulators Rehearing Request at 15-16; Utah Commission Rehearing Request at 8; *cf.* Arizona Commission Rehearing Request at 16 (citing the cost of achieving net-zero on the transmission grid).

infrastructure to Order No. 1920. Regardless, while the economic impact is relevant to this inquiry, the major questions doctrine is a nuanced, context-specific doctrine that does not require clear congressional authorization for every agency action that may have significant economic consequences or addresses a significant problem.[560]

184. We also are not persuaded by SERTP Sponsors' arguments that, unless the Commission grants its requests for clarification, Order No. 1920 runs afoul of the major questions doctrine, encroaches on state jurisdiction, or otherwise exceeds the Commission's authority. SERTP Sponsors do not clearly set forth the basis for many of their purported concerns regarding the Commission's statutory authority or application of the major questions doctrine, or even which arguments raise these concerns. For instance, while SERTP Sponsors identify Sections II.A.1 and II.C.3 of their argument as particularly raising these concerns,[561] in their Statement of Issues they more broadly state that the clarifications in "Sections II.A and II.C" of their argument are necessary to avoid intruding into state jurisdiction or application of the major questions doctrine.[562] But it is far from clear, and SERTP Sponsors do not explain, why many of the requested clarifications in Sections II.A and II.C would be necessary to avoid SERTP Sponsors'

[560] *See id.*; *cf. also* Arizona Commission Rehearing Request at 6 ("Under *West Virginia*, a major doctrinal change in the law, and the making of a federal rule that fundamentally reshapes policy, has to be done pursuant to an express statement of Congress"); Idaho Commission Rehearing Request at 6.

[561] SERTP Sponsors Rehearing Request at 39; *see also id.* at 41, 43 (issue statements 1 and 15).

[562] *Id.* at 44-45.

stated concerns about the Commission failing to afford adequate respect to state-approved integrated resource plans and load-serving entities' supply obligations or otherwise implicate concerns that the Commission is intruding into state jurisdiction.[563] Certain of SERTP Sponsors' other claims that, absent clarification, other aspects of Order No. 1920 would exceed the Commission's authority, are single-sentence assertions that provide little or nothing to illuminate why they believe this is the case.[564]

185. We address SERTP Sponsors' requests for clarification on their substance at various points in our discussion below. In several instances, we find that SERTP Sponsors have failed to plead their arguments that, absent their requested clarification, the Commission has exceeded its authority with the specificity required on rehearing, and

[563] *See, e.g.*, *id.* at 7-8 (arguing that states should be allowed to lengthen the time, upon agreement or motion, to reach an agreement as to cost allocation method); *id.* at 8 (requesting clarification on voluntary funding opportunities); *id.* at 11-12 (arguing that Long Term Transmission Needs have been defined in a circular fashion and that transmission providers should have discretion to use their expertise where they lack certain information); *id.* at 12-17 (requesting clarification that the factors affecting a single assumption will not necessarily have an additive effect; clarification on how specific factors will be identified; clarification on whether the Commission has expanded what constitutes legally binding obligations; and rehearing regarding adoption of Factor Category Seven).

[564] *See id.* at 41 ("Absent the requested clarification in section II.A.2, the six-month period permitted for states to negotiate an extension of the time period [*sic*] for negotiating *ex ante* or *ex post* state agreements on cost allocation, Order No. 1920 is contrary to FPA section 201, is *ultra vires*, and arbitrary and capricious"); *id.* ("Absent the requested clarification in section II.A.3, Order No. 1920 is contrary to FPA section 201 because it effectively mandates selection and/or construction of an LTRTF."); *id.* at 43 ("Absent the clarifications requested in section II.C.2.d, requiring the utilization of Factor Category Seven intrudes into matters involving retail customers subject to state regulation, thereby being ultra vires and contrary to FPA section 201.").

we reject them on that basis.[565] Regardless, to the extent that we do not grant those requests for clarification, whether in whole or in part, we find that the explanations in Order No. 1920 and herein establishing that Order No. 1920 is within the Commission's authority, does not unlawfully intrude into state areas of reserved authority, and does not implicate the major questions doctrine render SERTP Sponsors' arguments to the contrary unpersuasive. Where we believe further additional explanation is warranted in response to addressing a specific request for clarification made by SERTP Sponsors, we provide that explanation in conjunction with addressing the relevant request for clarification.

### D. Other Issues

#### 1. Requests for Rehearing

186. Several of the parties seeking rehearing argue that Order No. 1920 is not supported by the D.C. Circuit's decision in *South Carolina Public Service Authority v. FERC*, asserting that the Commission has attempted to direct substantive outcomes affecting the generation resource mix. Arizona Commission contends that Order No. 1000 "confined mandatory consideration [of factors affecting transmission needs] to pertinent laws and regulations, whereas Order No. 1920 now mandates consideration of broader 'policy goals,'" which are "more nebulous political agendas susceptible to significant fluctuations."[566] It contends that the Commission "is not authorized to compel Arizona to

[565] *See ZEP Grand Prairie Wind, LLC*, 183 FERC ¶ 61,150, at P 10 (2023); *see also Ind. Util. Regul. Comm'n v. FERC*, 668 F.3d 735, 736 (D.C. Cir. 2012)

[566] Arizona Commission Rehearing Request at 12-13 (arguing also that Arizona

use specific energy resources."[567] Montana Commission, West Virginia Commission, and Wyoming Commission argue that Order No. 1000 was upheld in *South Carolina Public Service Authority v. FERC* because of its light touch, which did not mandate a "backstop" *ex ante* cost allocation method to a voluntary state agreement, whereas Order No. 1920 has placed states in the untenable position of either agreeing to unjust and unreasonable cost allocations or having that burden foisted on them by default.[568] They further assert that Order No. 1920's "influence over the selection of transmission projects will inevitably affect resource planning and selection at the state level," invading the jurisdiction of the states.[569] Utah Commission argues that Order No. 1920, unlike Order No. 1000, "patently dictates outcomes and cost allocation and does so to discriminate and favor the policy preferences of certain preferred stakeholders."[570]

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law "does not allow the [Arizona Commission] to adopt, create, or mandate energy policy goals, and Order No. 1920's effort to compel the [Arizona Commission] to do so is unlawful" and that Order No. 1920's approach will lead to unjust cost allocations wherein states without renewable policy objectives must absorb costs generated by the transmission of renewable energy).

[567] *Id.* at 13.

[568] *See* Montana Commission Rehearing Request at 2-4; West Virginia Commission Rehearing Request at 10-12; Wyoming Commission Rehearing Request at 2-4.

[569] *See* Montana Commission Rehearing Request at 4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 4.

[570] Utah Commission Rehearing Request at 8 n.17.

187. Undersigned States and Designated Retail Regulators argue that Order No. 1920 "mandates transmission planning criteria that marginalize the input from Relevant Electric Retail Regulatory Authorit[ies] [(RERRAs)] in transmission planning, instead favoring selected generation."[571] In particular, they argue that Order No. 1920 adopts monolithic nationwide criteria that remove the states' role in planning and cost allocation, and that those criteria are "designed to allow the preferred policy goals of certain states, utilities, and corporate interests to dictate transmission planning for all," rather than prioritizing reliability and consumer impacts.[572] Similarly, Georgia Commission argues that Order No. 1920 "violates the states' reserved decision-making power by requiring that the states measure their long-term transmission plans against seven factors identified in the Order."[573]

188. Relatedly, Montana Commission, West Virginia Commission, and Wyoming Commission argue that Order No. 1920 undermines states' role in transmission planning and ratemaking, and does not result in just and reasonable rates.[574] In particular, they

[571] Undersigned States Rehearing Request at 7-8; *see id.* at 24-26; Designated Retail Regulators Rehearing Request at 8, 24-26.

[572] Undersigned States Rehearing Request at 24; *id.* at 26 ("With its rigid planning and cost allocation criteria, the Rule will result in the imposition of massive transmission costs necessary to accomplish certain states' policy goals upon other states."); Designated Retail Regulators Rehearing Request at 24-26 (similar).

[573] Georgia Commission Rehearing Request at 4.

[574] *See* Montana Commission Rehearing Request at 6-7 (arguing that a significant share of the costs of transmission facilities are allocated to retail customers, a question which is best left to the expertise of the states); West Virginia Commission Rehearing

assert that under Order No. 1920, transmission providers would be required to plan projects while considering the policy goals of various states (e.g., decarbonization), such that "the leading transmission projects may not be the most economical, let alone necessary, but for the policy goals of other states."[575] They contend that the costs allocated to retail customers may exceed the benefits that state policy recognizes from regional transmission projects, such that state commissions "would be forced to either assign unjust and unreasonable rates to retail customers, or deny the utility a potentially significant portion of its expected cost recovery."[576] Arizona Commission argues that Order No. 1920 usurps state authority mandating that it "apply rates that are fair and reasonable and not to cost share with rate payers who did not cause (and do not benefit from) a particular cost."[577]

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Request at 9-10; Wyoming Commission Rehearing Request at 6-8.

[575] *See* Montana Commission Rehearing Request at 6-7; West Virginia Commission Rehearing Request at 9-10; Wyoming Commission Rehearing Request at 7-8.

[576] Montana Commission Rehearing Request at 6-7 (noting that the Montana Commission typically conducts *post hoc* rather than *ex ante* rate reviews and that it is not clear that Order No. 1920 is designed to accommodate this process); West Virginia Commission Rehearing Request at 9-10; Wyoming Commission Rehearing Request at 7-8.

[577] Arizona Commission Rehearing Request at 20-22 (claiming that Order No. 1920 "usurps the Arizona Constitution and its methodology" because it "provides several factors that must be considered in transmission planning and cost allocation" which "include neither the fairness nor reasonableness of the costs nor any consideration of who causes the costs mandated by the FPA").

189. Arizona Commission also states that it owes its existence to the Arizona Constitution and that it has plenary power to set just and reasonable rates and charges collected by public service corporations.[578] It asserts that even the Arizona state legislature is "precluded by state constitutional law from legislating rate making decisions," and contends that, by the same token, the federal government "is certainly precluded from directing Arizona utilities to adopt energy plans that could cost hundreds of billions of dollars to Arizona consumers."[579]

190. On rehearing, Undersigned States again argue that Order No. 1920 is beyond the Commission's authority because, if the FPA were interpreted to authorize the rule, it "would likely violate the Constitution's equal sovereignty doctrine."[580] They argue that Order No. 1920 "sets up a scheme where one state can effectively require other states to subsidize their own public policy agenda—a core, sovereign state function."[581] Undersigned States also now bring a single sentence argument that "even if the Rule were supported by statutory authorization . . . then it would violate the nondelegation

[578] *Id.* at 7-9.

[579] *Id.* at 8-9.

[580] Undersigned States Rehearing Request at 18-19.

[581] *Id.* (arguing that Order No. 1920 subverts the democratic process, encroaches on state prerogatives, and is inconsistent with principles of cooperative federalism (citing *Coyle v. Smith*, 221 U.S. 559, 567 (1911); *Franchise Tax Bd. v. Hyatt*, 578 U.S. 171, 179 (2016); *Stearns v. Minn.*, 179 U.S. 223, 245 (1900); *Shelby Cnty. v. Holder*, 570 U.S. 529, 544 (2013)).

doctrine," on the theory that Congress is entirely precluded from delegating any "major policy question[s]" to agencies.[582]

191. Ohio Commission Federal Advocate contends that in issuing Order No. 1920 the Commission has violated the Commerce Clause because Commission authority "does not reach . . . attempts to use it to assist utilities and corporations with meeting their goals and commitments."[583] It particularly asserts that "[t]he U.S. Supreme Court has held that in the absence of federal legislation, commerce is generally open to control by states" and that Order No. 1920 will disproportionately benefit certain states, e.g., those with policies in favor of electrification of the transportation and building sectors.[584]

### 2. Commission Determination

192. We find that arguments that Order No. 1920 is not supported by the D.C. Circuit's decision in *South Carolina Public Service Authority v. FERC* upholding Order No. 1000 are erroneous because, as the court in that case put it, they "misperceive[ ] what the

[582] *Id.* at 17-18 (citing *Paul v. U.S.*, 140 S. Ct. 342, 342 (2019) (Mem.) (Kavanaugh, J., statement respecting denial of certiorari); *Indus. Union Dep't, AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. 607, 685-86 (1980) (Rehnquist, J., concurring in judgment); *A.L.A. Schechter Poultry Corp. v. U.S.*, 295 U.S. 495 (1935)).

[583] Ohio Commission Federal Advocate Rehearing Request at 18-19 (citing *City of Phila. v. N.J.*, 437 U.S. 617, 623 (1978); *Gen. Motors Corp. v. Tracy*, 519 U.S. 278, 300 (1997); *H. P. Hood & Sons, Inc. v. Du Mond*, 336 U.S. 525 (1949); *N.Y. v. U.S.,* 505 U.S. 144 (1992); *Printz v. United States*, 521 U.S. 898 (1997)).

[584] *Id.* (also arguing that Order No. 1920 will also benefit certain types of generation developers).

Commission has required in the Final Rule."[585] Order No. 1920 is directed toward ensuring just and reasonable rates by requiring Long-Term Regional Transmission Planning, including requiring transmission providers to evaluate which Long-Term Regional Transmission Facilities will more efficiently or cost-effectively address Long-Term Transmission Needs.[586] As in *South Carolina Public Service Authority v. FERC*,[587] the Commission has declined to impose obligations to "mandate development of any particular transmission facility,"[588] change applicable siting requirements and processes,[589] or "change existing mechanisms for cost-recovery through retail rates."[590] Order No. 1920 "does not regulate, aim at, or otherwise attempt to influence integrated resource planning, the generation mix, decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states

[585] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 57.

[586] Order No. 1920, 187 FERC ¶ 61,068 at PP 134, 667, 721-723.

[587] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 57-58 (explaining that the Commission did not impose obligations to build or mandatory processes to construct transmission facilities in the regional transmission plan and disavowed that it was purporting to determine what needs to be built, where it needs to be built, and who needs to build it); *see id.* at 62 ("The orders neither require facility construction nor allow a party to build without securing necessary state approvals.").

[588] Order No. 1920, 187 FERC ¶ 61,068 at P 257; *see id.* P 419 ("We are not requiring that transmission providers select any particular Long-Term Regional Transmission Facility and therefore are not directing the development of any particular transmission facilities.").

[589] *See id.* P 258.

[590] *Id.* P 259.

under FPA section 201."[591] Under Order No. 1920, like Order No. 1000, "the substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities remain within the discretion of the decision-makers in each planning region."[592] The Commission also maintains Order No. 1000's light touch as to regional cost allocation: "[i]t does not dictate how costs are to be allocated. Rather, the Rule provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes."[593]

193. We disagree with the arguments in the rehearing requests that Order No. 1920 attempts to direct substantive outcomes, including as to the generation resource mix.[594] As already explained, Order No. 1920 remains process-focused and does not seek to achieve particular substantive outcomes, influence or direct the generation mix, preferentially favor certain transmission facilities, or require unlawful subsidization of

[591] *Id.* P 254; *see also id.* P 256 ("[W]e direct reforms to close these gaps without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal in the face of similar objections to those raised here.").

[592] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 58.

[593] *Id.* at 81; *see, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at PP 268-269, 723, 916, 954, 1291-1294.

[594] *See* Arizona Commission Rehearing Request at 12-13; Montana Commission Rehearing Request at 3-4; West Virginia Commission Rehearing Request at 10-12; Wyoming Commission Rehearing Request at 2-4; Utah Commission Rehearing Request at 8 n.17.

state policies.[595] While it requires consideration of certain categories of factors in assessing Long-Term Transmission Needs,[596] these factors are resource-neutral and, within the broad parameters set by Order No. 1920, transmission providers have significant discretion in developing Long-Term Scenarios that further precludes the Commission from attempting to dictate outcomes.[597] Moreover, as described, transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to state public policies in Long-Term Regional Transmission Planning assumptions.

194. We disagree with claims that Commission has departed from the "light touch" of Order No. 1000 because Order No. 1000 did not mandate a "backstop" *ex ante* cost allocation method to a voluntary State Agreement Process.[598] As *South Carolina Public Service Authority v. FERC* recognized and upheld, Order No. 1000 required transmission providers to file an *ex ante* cost allocation method.[599] Order No. 1920 did not diminish

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[595] *See infra* Requirement to Incorporate Categories of Factors section.

[596] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 300 ("Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000. Where Long-Term Transmission Needs differ is their identification through the long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes established in this final rule.").

[597] *See infra* Requirement to Incorporate Categories of Factors section.

[598] *See* Montana Commission Rehearing Request at 2-4; West Virginia Commission Rehearing Request at 10-12; Wyoming Commission Rehearing Request at 2-4.

[599] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 53 ("The cost-allocation

states' role compared to Order No. 1000 but, instead, increased the available opportunities for robust participation by Relevant State Entities to seek to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[600] By virtue of these requirements, Order No. 1920 is more solicitous of state input and uses an even lighter touch than Order No. 1000 in this respect. As discussed elsewhere,[601] we take further steps in this rehearing order to strengthen states' role in Long-Term Regional Transmission Planning and cost allocation for Long-Term Regional Transmission Facilities.

195. We are also not persuaded by arguments that Order No. 1920 exceeds the Commission's authority because it thwarts the role of RERRAs[602] or unlawfully intrudes on the authority of state bodies that regulate retail rates.[603] Order No. 1920 "does not

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reforms in Order No. 1000 require each transmission provider to include in its OATT a method (or set of methods) for allocating *ex ante* the costs of new regional transmission facilities that complies with six regional cost allocation principles." (citing Order No. 1000, 136 FERC ¶ 61,051 at P 558)); *see id.* at 82-87 (rejecting challenges to the Commission's authority to adopt such reforms).

[600] *See id.* PP 5, 268, 1291.

[601] *Infra* Transmission Planning Horizon section; Obligation to File an *Ex Ante* Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section.

[602] *See* Undersigned States Rehearing Request at 7-8; Designated Retail Regulators Rehearing Request at 8, 24-26; Georgia PSC Rehearing Request at 4.

[603] *See* Montana Commission Rehearing Request at 6-7; West Virginia Commission Rehearing Request at 9-10; Wyoming Commission Rehearing Request at 6-8; Arizona Commission Rehearing Request at 20-22 (arguing that the primary focus of transmission planning and cost allocation has been reliability and low cost, and that

change existing mechanisms for cost-recovery through retail rates," but, instead, regulates transmission planning and cost allocation processes falling within the Commission's jurisdiction.[604] To the extent that Order No. 1920 might affect retail rates or other areas of state authority, this does not defeat the Commission's authority; as a valid exercise of the Commission's jurisdiction over practices affecting interstate transmission rates, Order No. 1920 is lawful notwithstanding such effects.[605] Finally, assertions that the Commission is attempting to dictate substantive outcomes or prefer certain energy resources or policies or that Order No. 1920 does not comport with principles of cost causation[606] are not convincing for the reasons already explained.[607]

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Order No. 1920 introduces other considerations).

[604] Order No. 1920, 187 FERC ¶ 61,068 at P 259.

[605] *See supra* Federal/State Division of Authority section; *EPSA*, 577 U.S. at 281-82 ("When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, *then no matter the effect* on retail rates, 824(b) imposes no bar." (emphasis added))); *see also* Arizona Commission Rehearing Request at 20-22 (claiming that Order No. 1920 "usurps the Arizona Constitution and its methodology" and otherwise conflicts with state law); U.S. Const. Art. VI ("This Constitution, and the Laws of the United States which shall be made in Pursuance thereof . . . shall be the supreme Law of the Land . . . any Thing in the Constitution or Laws of any State to the Contrary notwithstanding."); *NARUC*, 964 F.3d at 1186-88 (discussing the application of the Supremacy Clause in the context of the FPA in rejecting an argument that a Commission regulation unlawfully regulated matters falling within state authority).

[606] *See, e.g.*, States Rehearing Request at 7-8, 24; Designated Retail Regulators Rehearing Request at 8, 25-26; Georgia PSC Rehearing Request at 4; Arizona Commission Rehearing Request at 22; Utah Commission Rehearing Request at 9.

[607] *See supra* Federal/State Division of Authority section(explaining that Order No. 1920 is not directed at achieving substantive outcomes and that the categories of factors are resource-neutral); *supra* Order No. 1920 Does Not Require Unlawful

196. We are also not persuaded by Undersigned States' argument[608] that if Order No. 1920 were authorized by the FPA, the FPA would violate equal sovereignty principles. The Commission in Order No. 1920 explained at length its reasons for rejecting that argument.[609] On rehearing, Undersigned States repeat their arguments from their comments on the NOPR while failing to engage with, let alone rebut, the Commission's reasoning in Order No. 1920.[610] We therefore sustain Order No. 1920's rejection of this argument for the reasons stated therein. We particularly note that Undersigned States have pointed to no precedent applying the equal sovereignty doctrine in circumstances comparable to those here.[611]

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Subsidization of State Policies section (explaining that arguments that the Commission is requiring subsidization of state policies are incorrect and unpersuasive).

[608] Undersigned States Rehearing Request at 18-19.

[609] Order No. 1920, 187 FERC ¶ 61,068 at PP 280-282 (explaining that this argument was not supported by precedent and is incorrect because Order No. 1920 does not require subsidization of other states policies or generation decisions).

[610] *See* Undersigned States Rehearing Request at 18-19; Order No. 1920, 187 FERC ¶ 61,068 at P 212 & n.535 (citing Undersigned States Reply Comments at 5-6).

[611] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 280-282. In addition to the discussion in Order No. 1920, we observe that, unlike here, the cases on which Undersigned States rely addressed the validity of direct and *de jure* limitations of the rights of certain states relative the rights provided to other states. *See Franchise Tax Bd. v. Hyatt,* 578 U.S. at 178 (explaining that Nevada "has applied a special rule of law applicable only in lawsuits against its sister States"); *Shelby Cnty. v. Holder*, 570 U.S. at 544 ("And despite the tradition of equal sovereignty, the Act applies to only nine States (and several additional counties)."); *Coyle v. Smith*, 221 U.S. at 579 ("Has Oklahoma been admitted upon an equal footing with the original states? If she has, she, by virtue of her jurisdictional sovereignty as such a state, may determine for her own people the proper location of the local seat of government."); *cf. Stearns v. Minn.*, 179 U.S. at 244-45 (discussing the validity of certain provisions of the enabling act admitting Minnesota

197. Also unpersuasive is Undersigned States' nondelegation argument.[612] To begin with, this argument was not raised prior to rehearing, as required by the Commission's Rule of Practice and Procedure 713(c)(3).[613] We typically do not consider arguments raised for the first time on rehearing, unless those arguments could not have been previously presented, e.g., claims based on information that only recently became available or concerns prompted by a change in material circumstances.[614] Commenters had the opportunity to raise this argument, but did not do so.[615]

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to the Union, as incorporated in the Minnesota Constitution, in noting that "a state admitted into the Union enters therein in full equality with all the others").

[612] *See* Undersigned States Rehearing Request at 17-18.

[613] *See* 18 CFR 385.713(c)(3) (providing that any request for rehearing must "[s]et forth the matters relied upon by the party requesting rehearing, if rehearing is sought based on matters not available for consideration by the Commission at the time of the final decision or final order").

[614] *See Ala. Power Co.*, 179 FERC ¶ 61,128, at P 15 (2022); *KEI (Me.) Power Mgmt. (III) LLC*, 173 FERC ¶ 61,069, at P 38 n.77 (2020); *Tex. E. Transmission, LP*, 141 FERC ¶ 61,043, at P 19 (2012) ("We do so because (1) our regulations preclude other parties from responding to a request for rehearing and (2) such behavior is disruptive to the administrative process because it has the effect of moving the target for parties seeking a final administrative decision." (quotation marks omitted)); *Calpine Oneta Power v. Am. Elec. Power Serv. Corp.*, 114 FERC ¶ 61,030, at P 7 (2006); *Iroquois Gas Transmission Sys., L.P.*, 86 FERC ¶ 61,261, at 61,949 (1999)); *Ocean State Power II*, 69 FERC ¶ 61,146, at 61,548 (1994); *NO Gas Pipeline v. FERC*, 756 F.3d 764, 770 ("We finally note that Jersey City's alleged constitutional claim of actual bias is also barred as untimely. Jersey City has shown us nothing of record to establish that it raised this issue before FERC's issuance of the initial order.").

[615] *See U.S. v. L.A. Tucker Truck Lines, Inc.*, 344 U.S. 33, 37 (1952) ("Simple fairness to those who are engaged in the tasks of administration, and to litigants, requires as a general rule that courts should not topple over administrative decisions unless the administrative body not only has erred but has erred against objection made at the time appropriate under its practice."); *cf. Reytblatt v. U.S. Nuclear Regul. Comm'n*, 105 F.3d

198. In any event, a statute does not violate the nondelegation doctrine so long as Congress has set forth an "intelligible principle" to guide the delegee's exercise of authority.[616] Undersigned States fail to apply (or even acknowledge) this test, address the precedent setting it forth, or engage with the text of the FPA.[617] Instead, distinct from their major questions doctrine argument, they assert a *per se* bar on Congress delegating "major policy questions" to agencies.[618] They cite no case adopting this sweeping rule,[619] and we therefore decline to apply this approach here.[620] Moreover, Undersigned States'

715, 723 (D.C. Cir. 1997) (agencies are not required to respond to untimely comments).

[616] *Whitman v. Am. Trucking Ass'ns*, 531 U.S. at 472 (citing *J.W. Hampton, Jr., & Co. v. United States*, 276 U.S. 394, 409 (1928)); *see also Fox Television Stations, Inc.*, 556 U.S. at 536; *Nat'l Postal Pol'y Council v. Postal Regul. Comm'n*, 17 F.4th 1184, 1192 (D.C. Cir. 2021).

[617] *Cf. Gundy v. United States*, 588 U.S. 128, 146 (2019) (plurality opinion) ("We have sustained authorizations for agencies to set "fair and equitable" prices and "just and reasonable" rates." (citing *Yakus v. United States*, 321 U.S. 414, 422, 427 (1944); *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944)).

[618] *See* Undersigned States Rehearing Request at 17-18.

[619] *See id.* (citing *Paul v. U.S.*, 140 S. Ct. at 342 (2019) (Mem.) (Kavanaugh, J., statement respecting denial of certiorari) (expressly recognizing that "the Court has not adopted a nondelegation principle for major questions"); *Union Dep't, AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. at, 685-86 (Rehnquist, J., concurring in judgment) (similar); *A.L.A. Schechter Poultry Corp. v. United States*, 295 U.S. 495).

[620] This argument is also in tension with the Court's articulation of the major questions doctrine in *West Virginia*. *See* 597 U.S. at 721, 723 (explaining that the major questions doctrine applied only in extraordinary cases, based on specific statutory context and a variety of factors, and that "delegation[s]" to address major questions were permissible with clear congressional authorization); *cf. Paul v. U.S.*, 140 S. Ct. at 342 (Mem.) (Kavanaugh, J., statement respecting denial of certiorari) (recognizing that application of this test would overturn the aspect of major questions doctrine allowing Congress to "delegate to the agency the authority both to decide the major policy

single-sentence argument fails to explain the parameters of this test or how we would apply it to the statutory text of the FPA or Order No. 1920. And even were we to set aside the foregoing, we would still disagree that Order No. 1920 involves the delegation of such a "major policy question" for the reasons stated herein and in Order No. 1920.[621]

199. Finally, Ohio Commission Federal Advocate incorrectly claims that Order No. 1920 "violates the federal Commerce Clause" on the theory that Order No. 1920 may disproportionately benefit commerce in certain states, which have implemented policies allegedly favored by the rule, as compared to other states.[622] As discussed above, Order No. 1920 is a valid exercise of congressionally granted authority under the FPA. It does not favor particular state policies or transmission planning outcomes, but rather takes state policies as inputs into Long-Term Regional Transmission Planning.[623] Furthermore, the precedent that Ohio Commission Federal Advocate cites does not support concluding that a generally applicable Commission rule promulgated pursuant to its authority under the FPA (itself a valid exercise of Congress's Commerce Clause authority) violates the Commerce Clause if that rule may have disparate effects on commerce in various states.[624]

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question and to regulate and enforce").

[621] *See supra* Major Questions Doctrine section; Order No. 1920, 187 FERC ¶ 61,068 at PP 253-62, 275-78.

[622] Ohio Commission Federal Advocate Rehearing Request at 18-19.

[623] *See supra* Federal/State Division of Authority section.

[624] *See* Ohio Commission Federal Advocate Rehearing Request at 18-19; *Gen.*

## V. Long-Term Regional Transmission Planning

### A. Requirement to Participate in Long-Term Regional Transmission Planning

#### 1. Order No. 1920 Requirements

200. In Order No. 1920, the Commission required transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs. The Commission required that Long-Term

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*Motors Corp. v. Tracy*, 519 U.S. at 281-82, 287-88, 311-12 (addressing whether state sales and use taxes were impermissible as discriminatory under dormant Commerce Clause or Equal Protection Clause jurisprudence; holding that the taxes violated neither provision of the Constitution); *City of Phila. v. N.J.*, 437 U.S. at 623 (similarly addressing issues arising under dormant Commerce Clause jurisprudence, in the absence of controlling federal legislation, particularly as to whether New Jersey could close its borders to importation of certain waste); *H. P. Hood & Sons, Inc. v. Du Mond*, 336 U.S. at 545 ("Since the [state] statute as applied violates the [dormant] Commerce Clause and is not authorized by federal legislation pursuant to that Clause, it cannot stand."); *cf. Printz v. United States,*, 521 U.S. at 935 ("We held in *New York* that Congress cannot compel the States to enact or enforce a federal regulatory program. Today we hold that Congress cannot circumvent that prohibition by conscripting the State's officers directly."); *New York v. U.S.* 505 U.S. at 161 ("This litigation . . . concerns the circumstances under which Congress may use the States as implements of regulation . . . .").

Regional Transmission Planning comply with the following Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[625]

201. The Commission explained that Long-Term Regional Transmission Planning will enhance the existing regional transmission planning and cost allocation processes required by Order No. 1000. The Commission also stated that, except as set forth in Order No. 1920, it does not require any transmission provider to replace or otherwise make changes to its existing Order No. 1000-compliant regional transmission planning processes that plan for reliability or economic transmission needs, or the associated Order No. 1000-compliant regional cost allocation method(s). As such, the Commission explained, transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.[626] The Commission also declined a request to mandate that the "base cases" used in Order No. 1000 regional transmission planning processes and the Long-Term Scenarios used in Long-Term Regional Transmission Planning be defined in the same process.[627]

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[625] Order No. 1920, 187 FERC ¶ 61,068 at P 224.

[626] *Id.* P 241.

[627] *Id.* P 246.

202. The Commission further explained that Order No. 1920 does not alter the existing Order No. 1000 requirement to consider Public Policy Requirements in the regional transmission planning process, and further stated that it will instead deem transmission providers to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set for in Order No. 1920.[628] The Commission allowed transmission providers to propose in their Order No. 1920 compliance filings to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements. The Commission held that transmission providers nevertheless must comply with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920, such that continued use of existing regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements will not supplant transmission providers' obligation to comply with Order No. 1920. The Commission required that, in their Order No. 1920 compliance filings, transmission providers that wish to continue to use some or all of their existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in Order No. 1920.[629]

[628] *Id.* P 242.

[629] *Id.* P 243.

203. The Commission also allowed transmission providers to propose a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs, as well as Long-Term Transmission Needs as defined in Order No. 1920, through a combined process. The Commission required transmission providers proposing to address all of these transmission needs in a single regional transmission planning process to demonstrate that such a unified regional transmission planning process continues to comply with Order No. 1000, as well as with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order Nos. 1000 and 1920. The Commission explained that, in the case that the requirements of Order Nos. 1000 and 1920 conflict, the Order No. 1920 requirements will prevail, and transmission providers must demonstrate that their proposed regional transmission planning process is consistent with or superior to the applicable Order No. 1920 requirements.[630]

204. As described further in the Implementation of Long-Term Regional Transmission Planning section below, in Order No. 1920, the Commission required transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. The Commission required transmission providers to provide in their explanations any information necessary to ensure that stakeholders understand this

[630] *Id.* P 244.

interaction, including at least the following two components. First, the Commission required transmission providers to address the possible interaction between the transmission planning cycle for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. The Commission recognized that there may be overlap in the time horizon for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes and that these processes will likely inform each other.[631] Second, the Commission required transmission providers to address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. The Commission recognized that it is possible that, in some cases, Long-Term Regional Transmission Facilities selected to address Long-Term Transmission Needs may provide near-term reliability or economic benefits, and thus could displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.[632]

### 2. Requests for Rehearing and Clarification

205. Multiple parties request rehearing and clarification on the requirement that, in their Order No. 1920 compliance filings, transmission providers that wish to continue to use some or all of their existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate

[631] *Id.* P 1071.

[632] *Id.* (citation omitted).

that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in Order No. 1920. Large Public Power requests clarification that the Commission will presume the existing regional transmission planning and cost allocation processes that transmission providers use to consider transmission needs driven by Public Policy Requirements to be just and reasonable. Large Public Power claims that this is an issue on which the Commission was not clear in Order No. 1920, because the Commission stated that Order No. 1920 "do[es] not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process," that transmission providers may propose to continue using these processes, and that transmission providers proposing to do so "must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final rule."[633] Large Public Power contends that its members see value in existing regional transmission planning processes that transmission providers use to consider transmission needs driven by Public Policy Requirements, and requests that the Commission not disrupt these processes—in particular the process conducted by NYISO. Large Public Power describes certain aspects of NYISO's regional transmission planning process and explains that the New

[633] Large Public Power Rehearing Request at 4-6 (quoting Order No. 1920, 187 FERC ¶ 61,068 at PP 242-243).

York Commission and the Commission each have approved these processes.[634] Large Public Power therefore requests that, in reviewing transmission providers' Order No. 1920 compliance filings, the Commission presume that these existing processes are just and reasonable, and argues that the Commission should not require transmission providers and their stakeholders to face the burden of demonstrating that these processes are just and reasonable.[635] If the Commission does not grant clarification, Large Public Power requests rehearing on the ground that the Commission did not advance in Order No. 1920 any "cogent rationale" for treating regional transmission planning processes that consider Public Policy Requirements differently from those that plan for reliability or economic transmission needs.[636]

206. Similar to Large Public Power's rehearing request, Pennsylvania Commission argues that requiring transmission providers in Order No. 1920 to demonstrate that continued use of existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements does not interfere with or otherwise undermine Long-Term Regional Transmission Planning is an abuse of discretion, and that the Commission failed to engage in reasoned decision making.[637] Pennsylvania Commission further argues that this requirement is inconsistent with the

[634] *Id.* at 6-9.

[635] *Id.* at 4, 6, 9.

[636] *Id.* at 7.

[637] Pennsylvania Commission Rehearing Request at 2.

Commission's statements that, outside the context of Long-Term Regional Transmission Planning, Order No. 1920 will not "otherwise disturb[] the regional transmission planning structure required by Order No. 1000" or "inadvertently cause the re-litigation of aspects of those existing processes."[638] Pennsylvania Commission contends that Order No. 1920 requires full re-litigation on compliance of all processes used to satisfy Public Policy Requirements, including PJM's State Agreement Approach because it addresses state Public Policy Requirements.[639] Pennsylvania Commission argues that the Commission should amend Order No. 1920 to either remove this compliance requirement, explicitly limit it to processes used for Long-Term Regional Transmission Planning, or to clarify that PJM's State Agreement Approach does not interfere with Long-Term Regional Transmission Planning and therefore would not be subject to re-litigation.[640]

207. Similarly, PJM States request that the Commission clarify that PJM's State Agreement Approach does not conflict with Order No. 1920, and that states within PJM can continue to pursue public policies through the voluntary election of the State

[638] Order No. 1920, 187 FERC ¶ 61,068 at PP 252, 256; *see* Pennsylvania Commission Rehearing Request at 2.

[639] Pennsylvania Commission Rehearing Request at 2-3 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 243).

[640] *Id.*

Agreement Approach in its current form.[641] Pennsylvania Commission also supports and adopts the clarification request of PJM States.[642]

208. PIOs argue that existing Order No. 1000 regional transmission planning processes that plan for reliability or economic transmission needs are unjust, unreasonable, and unduly discriminatory, and they request rehearing of various aspects of Order No. 1920 to ensure that these existing processes complement Long-Term Regional Transmission Planning rather than conflict with and undermine it.[643] Citing a number of statements in Order No. 1920, PIOs contend that these existing regional transmission planning processes threaten the reliability of the transmission system, fail to build transmission infrastructure necessary to meet regional transmission needs over the long term, and instead invest in transmission facilities addressing narrower, shorter-term needs, which ultimately leads to transmission customers paying unjust and unreasonable rates.[644] PIOs contend that evidence in the record demonstrates that failing to address the "systemic inadequacies" of existing regional transmission planning processes or aligning them with Long-Term Regional Transmission Planning will perpetuate unjust and unreasonable rates.[645]

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[641] PJM States Rehearing Request at 6-7.

[642] Pennsylvania Commission Rehearing Request at 1.

[643] *See generally* PIOs Rehearing Request at 16-25.

[644] *Id.* at 16-18.

[645] *Id.* at 20.

209. PIOs therefore request that the Commission amend Order No. 1920 in three ways. First, PIOs argue that the Commission should require transmission providers either to conduct a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs through a combined process or to align the methods of all regional transmission planning processes, including Long-Term Regional Transmission Planning.[646] Second, PIOs argue that the Commission should delineate clear boundaries between and align the timing of Long-Term Regional Transmission Planning and existing processes, such that transmission providers would address only the limited regional transmission needs that cannot be reasonably anticipated and cannot be addressed during a Long-Term Regional Transmission Planning cycle. Otherwise, PIOs contend, these processes all would identify transmission facilities over the same planning periods despite different underlying assumptions, benefits assessments, and cost allocation.[647] Third, PIOs argue that the Commission should require Long-Term Regional Transmission Planning and existing processes to use the same "base case" embodying transmission providers' best assessment of future system conditions. Otherwise, PIOs contend, transmission providers ultimately may identify redundant transmission facilities, fail to identify more efficient or

[646] *Id.* at 21-23.

[647] *Id.* at 23-24.

cost-effective Long-Term Regional Transmission Facilities, or be motivated to undermine Long-Term Regional Transmission Planning in favor of existing processes.[648]

### 3. Commission Determination

210. We decline to grant the clarification sought by Large Public Power that the Commission will presume the existing regional transmission planning and cost allocation processes that transmission providers use to consider transmission needs driven by Public Policy Requirements to be just and reasonable. We disagree with Large Public Power that Order No. 1920 was unclear as to how the Commission will evaluate any proposals transmission providers may make in their compliance filings to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements. We also disagree with the Pennsylvania Commission that the Commission failed to engage in reasoned decision making. The Commission stated clearly in Order No. 1920, and we continue to find, that, while transmission providers may propose to retain existing Order No. 1000 regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements, transmission providers that do so must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in Order No. 1920.[649] In other words, the Commission will not presume the existing regional

[648] *Id.* at 24-25.

[649] Order No. 1920, 187 FERC ¶ 61,068 at P 243; *see also id.* P 240 (declining to pre-judge whether any existing regional transmission planning processes meet the

transmission planning and cost allocation processes used to consider transmission needs driven solely by Public Policy Requirements are just and reasonable.

211. We also disagree with Large Public Power's argument that the Commission did not justify the differential treatment of regional transmission planning processes that consider transmission needs driven by Public Policy Requirements compared to those that plan for reliability or economic transmission needs. The Commission found that conducting Long-Term Regional Transmission Planning as set forth in Order No. 1920 is sufficient to comply with the Order No. 1000 requirement to consider Public Policy Requirements in the regional transmission planning process. In other words, Long-Term Regional Transmission Planning may subsume the purpose of existing regional transmission planning and cost allocation processes used to consider transmission needs driven by Public Policy Requirements. Given that potential, it is necessary and appropriate to require transmission providers to demonstrate that continued use of Order No. 1000 processes to consider transmission needs driven by Public Policy Requirements does not interfere with or otherwise undermine Long-Term Regional Transmission Planning under Order No. 1920. We also note that Order No. 1920 allows transmission providers to propose a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs, as well as Long-Term Transmission Needs, through a combined process, and that transmission providers proposing to address all of these transmission needs in a single regional transmission

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requirements of Order No. 1920).

planning process must demonstrate that the combined regional transmission planning process continues to comply with Order No. 1000, as well as with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order No. 1000 and Order No. 1920.[650]

212. Similarly, we disagree with the Pennsylvania Commission that this requirement is inconsistent with the Commission's statements that, except for Long-Term Regional Transmission Planning, Order No. 1920 will not "otherwise disturb[] the regional transmission planning structure required by Order No. 1000" or "inadvertently cause the re-litigation of aspects of those existing processes."[651] That said, we appreciate the Pennsylvania Commission's concern that Order No. 1920 requires re-litigation of PJM's State Agreement Approach and its request that the Commission limit the requirement to processes used for Long-Term Regional Transmission Planning. We also recognize PJM States' request for clarification that PJM's State Agreement Approach does not interfere or conflict with Long-Term Regional Transmission Planning. As the Commission explained in Order No. 1920, this requirement does not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process, and transmission providers will be deemed to be in compliance with this existing requirement by conducting Long-Term Regional

[650] *Id.* P 244.

[651] *Id.* PP 252, 256; *see* Pennsylvania Commission Rehearing Request at 2-3.

Transmission Planning in accordance with the requirements set forth in Order No. 1920.[652] Thus, Order No. 1920 allows transmission providers to propose in their Order No. 1920 compliance filings to continue using some or all aspects of the existing Order No. 1000 regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements, if they so choose. But the Commission held that transmission providers nevertheless must comply with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920 and that continued use of existing Order No. 1000 regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements alone is insufficient to comply with Order No. 1920. Stated differently, transmission providers that wish to continue to use some or all of their existing Order No. 1000 regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that the continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in Order No. 1920.[653]

213. With respect to PJM's State Agreement Approach specifically, we note that it is separate and apart from PJM's compliance with the Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements.[654] Therefore, PJM's

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[652] Order No. 1920, 187 FERC ¶ 61,068 at P 242.

[653] *Id.* P 243.

[654] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 142 (2013) ("We find PJM's proposed State Agreement Approach is not needed for PJM to comply with

State Agreement Approach is unaffected by Order No. 1920's requirement to justify continued use of regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements. In response to PJM States and Pennsylvania Commission, we note that Order No. 1920 does not prohibit PJM from continuing to use its existing State Agreement Approach. If the Relevant State Entities in PJM agree to rely on PJM's existing State Agreement Approach as an Order No. 1920 State Agreement Process that applies to selected Long-Term Regional Transmission Facilities, and PJM agrees, PJM must propose and demonstrate on compliance that its State Agreement Approach complies with all of the State Agreement Process requirements set forth in Order No. 1920.

214. We also disagree with PIOs' rehearing arguments related to existing regional transmission planning processes that plan for reliability and economic needs and the relationship of these processes to Long-Term Regional Transmission Planning. First, we decline PIOs' request that we require transmission providers to conduct a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs through a combined process. We continue to find that transmission providers may propose on compliance

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the provisions of Order No. 1000 addressing transmission needs driven by public policy requirements. PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 . . . . Accordingly, the Commission need not find that the State Agreement Approach and corresponding cost allocation method comply with Order No. 1000.").

such a combined process, but we do not require that transmission providers do so because the difficulty of transitioning to this kind of combined regional transmission planning process may outweigh any potential benefits of requiring such a process.[655]

215. Furthermore, we find that requiring transmission providers to use a combined process to plan for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs is unnecessary to address the deficiencies in existing regional transmission planning and cost allocation requirements that the Commission identified in Order No. 1920. Specifically, the Commission found that existing regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[656] Because we find that Order No. 1920's Long-Term Regional Transmission Planning and cost allocation requirements adequately remedy these deficiencies, we decline to impose the additional requirements that PIOs suggest.

216. Second, we find premature PIOs' arguments as to the need to align methods and timing between existing regional transmission planning processes and Long-Term Regional Transmission Planning. In Order No. 1920, the Commission required

[655] Order No. 1920, 187 FERC ¶ 61,068 at P 245.

[656] *Id.* P 114.

transmission providers to explain how Long-Term Regional Transmission Planning will interact with existing regional transmission planning processes to plan for transmission needs driven by reliability concerns or economic considerations, including their timing and the potential that Long-Term Regional Transmission Facilities may displace transmission facilities that are under consideration in those processes.[657] The Commission will evaluate the interaction between these processes on compliance and address any potential issues with this interaction in the orders on transmission providers' compliance filings.

217. Third, we disagree with PIOs as to the necessity of requiring that transmission providers use the same "base case" in existing regional transmission planning and in Long-Term Regional Transmission Planning. The Commission neither proposed such a requirement in the NOPR nor adopted one in Order No. 1920, and we are not persuaded to adopt PIOs' suggestion in this order. However, we note that nothing in Order No. 1920 precludes transmission providers from using the same base case in existing regional transmission planning and in Long-Term Regional Transmission Planning if they so choose.

[657] *Id.* PP 1071-1073.

### B. Long-Term Scenarios Requirements

#### 1. Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs

##### a. Order No. 1920 Requirements

218. Order No. 1920 required transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, which is defined as a multi-step process to: (1) identify Long-Term Transmission Needs; (2) identify transmission facilities that meet such needs; (3) measure the benefits of those transmission facilities; and (4) evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.[658] Order No. 1920 defined Long-Term Transmission Needs as "transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors."[659]

219. Order No. 1920 generally addressed the identification of Long-Term Transmission Needs and the measurement of the benefits of Long-Term Regional Transmission Facilities separately.[660] The Commission stated, however, that transmission providers "must use [the seven required benefits] to help to inform their identification of Long-

[658] *Id.* P 224.

[659] *Id.* PP 39, 299.

[660] *E.g.*, *id.* P 224 (describing these two requirements as separate steps).

Term Transmission Needs."[661] The Commission provided an example of how transmission providers can use one of the required benefits (the production cost savings benefit, Benefit 3) to help identify Long-Term Transmission Needs.[662]

**b. Requests for Rehearing and Clarification**

220. PJM requests clarification that the Commission did not intend to require transmission providers to use any of the seven benefits outlined in Order No. 1920 to help inform the identification of Long-Term Transmission Needs. If the Commission did intend to require transmission providers to use the set of seven required benefits to help inform the identification of Long-Term Transmission Needs, PJM requests that the Commission grant rehearing, either to eliminate this requirement or to provide transmission providers with flexibility as to this requirement to accommodate regional differences. PJM asserts that Order No. 1920 contains only one discussion of a requirement for transmission providers to use the seven required benefits to help inform their identification of Long-Term Transmission Needs, and, as such, PJM questions whether the Commission intended to impose this requirement.[663] PJM further asserts that the Commission offered only one hypothetical example of how one of these seven

[661] *Id.* PP 301, 719; *see id.* P 667 n.1485, P 859 n.1910.

[662] *Id.* P 301 ("[W]hen transmission providers are working to identify Long-Term Transmission Needs, areas of significant congestion on the transmission system—where Long-Term Regional Transmission Facilities could reduce congestion and in turn facilitate production cost savings—may indicate a Long-Term Transmission Need.").

[663] PJM Rehearing Request at 24-26 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 301).

benefits might help inform the identification of Long-Term Transmission Needs, and PJM argues that the Commission did not provide any evidence, let alone substantial evidence, to demonstrate why transmission providers should be required to use the seven benefits to inform the identification of Long-Term Transmission Needs.[664] PJM further claims that requiring the use of all seven benefits outlined in Order No. 1920 to help inform the identification of Long-Term Transmission Needs is inconsistent with PJM's sponsorship model because, in such a model, transmission developers propose transmission facilities after and in response to identified transmission needs, such that using the benefits of such transmission facilities to identify transmission needs is circular.[665] PJM also asserts that the NOPR did not provide notice of the requirement that transmission providers use the seven benefits to help inform the identification of Long-Term Transmission Needs, and PJM therefore lacked opportunity to provide comments as to why the requirement is inappropriate for the PJM region.[666]

221. SERTP Sponsors argue that Order No. 1920 defines Long-Term Transmission Needs in a circular fashion by describing them as "transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors,"[667]

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[664] *Id.* at 25.

[665] *Id.* at 25-26.

[666] *Id.* at 25 n.103.

[667] SERTP Sponsors Rehearing Request at 11 (quoting Order No. 1920, 187 FERC

but also requiring that the seven required benefits should inform the identification of Long-Term Transmission Needs.[668] SERTP Sponsors claim that this creates a potential chicken-or-egg conundrum, because Long-Term Transmission Needs are driven by factors and must be identified before the use and measurement of the seven required benefits to evaluate Long-Term Regional Transmission Facilities.[669]

222. PIOs request three clarifications related to the requirement that transmission providers use the seven benefits to help to inform the identification of Long-Term Transmission Needs.[670] First, PIOs request that the Commission clarify what "help to inform" means in this context, in order to avoid an outcome in which the seven benefits are only considered superficially rather than as meaningful determinants of Long-Term Transmission Needs. Second, PIOs request that the Commission clarify that transmission providers may not identify Long-Term Transmission Needs solely on the basis of one of the Order No. 1000 "silos," e.g., reliability. PIOs claim that, if a transmission provider were to identify Long-Term Transmission Needs solely based on reliability, for example, and then use the seven required benefits only to compare potential solutions, the resulting set of needs would be incomplete, and the resulting solutions would be inefficient. Third,

¶ 61,068 at P 39).

[668] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 719).

[669] *Id.*

[670] PIOs Rehearing Request at 59 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 301, 719).

PIOs request clarification that the requirement to use the seven required benefits to help identify Long-Term Transmission Needs applies equally to transmission providers that use a competitive bidding process and to those that use a sponsorship model. Regarding the sponsorship model in particular, PIOs also request clarification as to how the Commission envisions the process by which transmission providers could use the seven required benefits to help identify needs, without these needs being so granular that the transmission provider has effectively defined a specific project.[671]

### c. Commission Determination

223. We agree with certain of the rehearing arguments raised by PJM and SERTP Sponsors and therefore we set aside the requirement for transmission providers to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs. Specifically, we find that PJM and SERTP Sponsors highlight potential challenges and difficulty transmission providers may have in implementing this requirement. As further explained below, although we find that it is appropriate to set this requirement aside, we clarify and emphasize that the identification of Long-Term Transmission Needs should rely on economic and reliability drivers.

224. In requiring transmission providers to use the set of seven required benefits to help to inform their identification of Long-Term Transmission Needs, the Commission intended in Order No. 1920 to ensure that transmission providers would use their experience evaluating both the reliability and economic benefits of transmission

[671] *Id.* at 59-60.

facilities—as reflected in the seven required benefits—and technical expertise assessing the transmission system to identify whether there are reliability issues or opportunities to relieve constraints that could be resolved through Long-Term Regional Transmission Facilities identified through Long-Term Regional Transmission Planning. Upon further consideration, we find that Order No. 1920's Long-Term Regional Transmission Planning requirements, including the requirements to develop Long-Term Scenarios using the minimum required Factor Categories,[672] to use the minimum required transmission planning horizon,[673] and to develop Long-Term Scenarios that are plausible and diverse,[674] taken together, will ensure that transmission providers identify Long-Term Transmission Needs.

225. Thus, we are clarifying here that the categories of factors will help transmission providers identify Long-Term Transmission Needs, consistent with the Commission's statements in Order No. 1920.[675] Potential Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs, as identified by the Long-Term Scenarios

[672] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

[673] *Id.* P 344.

[674] *Id.* P 414.

[675] *See id.* P 299 (stating that "the drivers of transmission needs are diverse and include, but are not limited to, evolving reliability concerns, changes in the resource mix, and changes in demand"); *id.* P 300 (stating that "Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000," which include both reliability and economic considerations).

and sensitivities, will then be evaluated for their economic and reliability benefits, which will ensure that Long-Term Regional Transmission Planning leads to transmission solutions that more efficiently or cost-effectively address reliability and economic transmission needs over the appropriate transmission planning horizon.[676]

226. Finally, because we are setting aside the requirement for transmission providers to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs, we find moot PIOs' request for clarification concerning this requirement.

### 2. Transmission Planning Horizon

#### a. Order No. 1920 Requirements

227. In Order No. 1920, the Commission required transmission providers in each transmission planning region to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. The Commission defined Long-Term Scenarios as scenarios that incorporate various assumptions using best available data inputs about the future electric power

[676] We note that this understanding that potential Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs are evaluated for both reliability and economic benefits is consistent with the Commission's determination in Order No. 1920 that, while transmission providers have significant flexibility to determine a regionally appropriate *ex ante* cost allocation, such cost allocation may not be based on a siloed approach that assumes Long-Term Regional Transmission Planning addresses only reliability or only economic needs. However, as also noted below, transmission providers and Relevant State Entities have broad flexibility to recognize the different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits. *See infra* General Benefits Requirements Related to Cost Allocation section.

system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs.[677] The Commission defined best available data inputs as data inputs that are timely, developed using best practices and diverse and expert perspectives, adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000, and reflect the list of factors that transmission providers account for in their Long-Term Scenarios.[678]

228. The Commission clarified that using a transmission planning horizon of no less than 20 years means that transmission providers must develop Long-Term Scenarios to identify Long-Term Transmission Needs that will materialize in the 20 years or more following the commencement of the Long-Term Regional Transmission Planning cycle.[679] The Commission explained that requiring a transmission planning horizon of not less than 20 years strikes a balance. On the one hand, the Commission stated, a 20-year transmission planning horizon extends far enough into the future that transmission providers can proactively identify Long-Term Transmission Needs that could be met with more efficient or cost-effective Long-Term Regional Transmission Facilities and allows sufficient time to identify, plan, obtain siting and permitting approval for, and construct more efficient or cost-effective Long-Term Regional Transmission Facilities. On the

[677] Order No. 1920, 187 FERC ¶ 61,068 at P 302.

[678] *Id.* P 633.

[679] *Id.* P 344.

other hand, the Commission found that there may be sufficient uncertainty regarding system conditions and transmission needs beyond a 20-year transmission planning horizon such that it may be challenging for transmission providers to forecast Long-Term Transmission Needs across that time period.[680]

229. In adopting the minimum 20-year transmission planning horizon requirement in Order No. 1920, the Commission disagreed that a 20-year transmission planning horizon could result in Long-Term Regional Transmission Planning based on speculative transmission needs. The Commission explained that the Long-Term Regional Transmission Planning requirements adopted in Order No. 1920 are designed to avoid over-building transmission in response to speculative transmission needs through a series of tools and safeguards, which include the requirement that transmission providers reevaluate Long-Term Regional Transmission Facilities in certain circumstances.[681]

230. The Commission also disagreed with requests that it adopt a shorter transmission planning horizon, reasoning that a shorter planning horizon would fail to sufficiently capture Long-Term Transmission Needs given that some drivers of such needs extend up to 20 years into the future. The Commission added that a shorter minimum transmission planning horizon might not allow for sufficient time to develop Long-Term Regional Transmission Facilities with long lead-time requirements or to compare alternative

[680] *Id.* P 345.

[681] *Id.* P 348.

transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.[682]

**b. Requests for Rehearing and Clarification**

231. Alabama Commission, Ohio Commission Federal Advocate, and Dominion seek rehearing of Order No. 1920's requirement that transmission providers in each transmission planning region develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[683]

232. Dominion contends that Order No. 1920 is arbitrary and capricious because the Commission failed to address Dominion's concerns regarding the use of a 20-year transmission planning horizon.[684] Dominion asserts that the Commission failed to address its NOPR comments, which argued that a 20-year transmission planning horizon runs the risk of essentially implementing a "transmission Integrated Resource Plan" that mandates potentially speculative transmission projects. Dominion avers that integrated resource plans are snapshots in time that show potential pathways for meeting future needs and are not concrete, definitive plans.[685] Dominion states that in its NOPR

[682] *Id.* P 349.

[683] Alabama Commission Rehearing Request at 4; Dominion Rehearing Request at 11-14; Ohio Commission Federal Advocate Rehearing Request at 20-21.

[684] Dominion Rehearing Request at 7, 12-15.

[685] *Id.* at 13-14 (citing Dominion NOPR Initial Comments at 18-19).

comments it explained that predicting the future resource mix is challenging and that numerous planning considerations that apply today could change over the next 20 years, which is why Dominion cautioned against requiring transmission providers to make investment and cost allocation decisions based on speculation 20 years into the future.[686]

233. According to Dominion, its NOPR comments also asserted that a 20-year transmission planning horizon requires using less reliable assumptions, which can lead to stranded or misallocated costs,[687] especially because cost allocation under Order No. 1920 could occur much earlier than before.[688] Dominion argues that planning further into the future decreases certainty, likely has diminishing returns, and requires transmission providers to deploy personnel with scarce planning expertise—a highly valuable resource—who could be used more efficiently by planning for likelier scenarios.[689]

234. Further, Dominion argues that because Order No. 1920 would not necessarily permit reevaluation in certain circumstances that could render a transmission project unnecessary—e.g., where changes in technology or load growth obviate the need for a project in a particular location—the reevaluation process is insufficient to address concerns regarding the speculative nature of a 20-year planning horizon.[690]

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[686] *Id.* at 14 (citing Dominion NOPR Initial Comments at 20).

[687] *Id.* (citing Dominion NOPR Initial Comments at 20).

[688] *Id.*

[689] *Id.* at 15.

[690] *Id.* at 16-18.

235. Dominion also argues that the Commission arbitrarily dismissed its requests for flexibility to adopt a timeline that is suited to a particular transmission planning region to reduce the risk of selection of transmission projects that may not actually be needed.[691] Dominion states that, if the Commission must prescribe a minimum transmission planning horizon, it would be more reasonable to continue allowing PJM/Dominion Energy Virginia to use a 15-year forecast horizon, which strikes a balance between long-term needs and avoiding speculative projects, and to continue allowing South Carolina Regional Transmission Planning/Dominion Energy South Carolina to use a 10-year transmission planning horizon. Such transmission planning horizons, Dominion claims, would be more tailored to the transmission planning regions' needs.[692]

236. Ohio Commission Federal Advocate also asserts that the Commission acted arbitrarily and capriciously and violated the consumer protection provisions of the FPA by adopting the 20-year transmission planning horizon requirement. Ohio Commission Federal Advocate argues that a 20-year transmission planning horizon puts transmission planners in the "impossible position" of having to predict the resource mix and location of resources 20 years in the future and will lead to inefficient and potentially unnecessary investment decisions.[693] In the alternative to seeking rehearing on the 20-year transmission planning horizon requirement, Ohio Commission Federal Advocate requests

[691] *Id.* at 15.

[692] *Id.* at 12-13, 16.

[693] Ohio Commission Federal Advocate Rehearing Request at 20-21.

that the Commission clarify that the 20-year planning horizon should be informational only and should not be relied upon for investment decisions until the future can be better ascertained.[694] Similarly, Alabama Commission contends that a 20-year transmission planning horizon is likely to produce speculative outputs that lack sufficient basis for actionable planning decisions and that action on these outputs should be determined at the state level to avoid costly transmission facilities that are not actually needed.[695]

### i. Commission Determination

237. We sustain the requirement that transmission providers in each transmission planning region develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. The Commission's adoption of a 20-year transmission planning horizon was reasonable and supported by record evidence,[696] and the Commission did not disregard arguments to the contrary. As the Commission explained in Order No. 1920, a transmission planning horizon of less than 20 years would fail to sufficiently capture Long-Term Transmission Needs given that drivers of such needs can extend up to 20 years into the future, such as state laws that include requirements to be met 15 to 20 years in the future.[697] In addition,

[694] *Id.* at 21.

[695] Alabama Commission Rehearing Request at 4.

[696] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 309-318 (describing support for a transmission planning horizon of at least 20 years).

[697] *Id.* P 349.

a 20-year transmission planning horizon allows for more time between when a transmission facility is identified to meet a future transmission need and when the transmission need materializes, allowing for sufficient time to identify, plan, obtain siting and permitting approval for, and construct Long-Term Regional Transmission Facilities.[698]

238. Moreover, we continue to find that a shorter minimum transmission planning horizon may not allow for sufficient time to develop Long-Term Regional Transmission Facilities with long lead-time requirements or to compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.[699] We therefore are not convinced by arguments that the Commission should have adopted a minimum transmission planning horizon shorter than 20 years.

239. We disagree with arguments that the minimum 20-year transmission planning horizon could result in the selection of speculative transmission projects or will lead to inefficient and potentially unnecessary investment decisions,[700] including Dominion's related argument that a 20-year transmission planning horizon runs the risk of "essentially implementing a transmission Integrated Resource Plan [] that mandates

[698] *Id.* P 345; *see also id.* P 312 (describing arguments of commenters whose comments supported a 20-year transmission planning horizon).

[699] *Id.* P 349.

[700] Alabama Commission Rehearing Request at 4; Dominion Rehearing Request at 11-15; Ohio Commission Rehearing Request at 20-21.

investments in potentially speculative transmission projects" or may result in imprecision and could lead to stranded or misallocated costs.[701] As the Commission found in Order No. 1920, the Long-Term Regional Transmission Planning requirements include tools and safeguards designed to avoid over-building transmission in response to speculative transmission needs.[702] These tools and safeguards include: (1) the requirement that transmission providers develop (and periodically update) multiple plausible and diverse Long-Term Scenarios based upon best available data; (2) transmission providers' flexibility to develop evaluation processes, including selection criteria, that will enable them to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities; and (3) the lack of a selection mandate.[703] We continue to find that, by facilitating regional transmission planning that accounts for a range of potential futures, Order No. 1920 ensures that transmission providers will be able to manage uncertainty, which, in turn, mitigates the risk of speculative transmission development.[704]

240. Although Dominion argues that the reevaluation process is insufficient to address concerns that a 20-year transmission planning horizon could lead to the selection of

[701] Dominion Rehearing Request at 13-14.

[702] Order No. 1920, 187 FERC ¶ 61,068 at P 348.

[703] *Id.* P 231.

[704] *Id.* P 229.

speculative transmission projects,[705] Dominion does not demonstrate how Order No. 1920's other tools and safeguards beyond the reevaluation requirement are individually or collectively insufficient to prevent over-building transmission in response to speculative transmission needs.[706] Moreover, robust scenario-planning allows transmission providers to compare the costs and benefits of Long-Term Regional Transmission Facilities under different future conditions, which informs selection and consequently helps to mitigate uncertainty.

241. In addition, as discussed later,[707] we also clarify that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to states' laws, policies, and regulations in transmission planning assumptions, which will ensure that such factors are effectively accounted for in the development of Long-Term Scenarios. We believe this clarification mitigates Ohio Commission Federal Advocate's concerns that the 20-year transmission planning horizon could result in unnecessary investment.[708] With this clarification, Order No. 1920

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[705] Dominion Rehearing Request at 16-18.

[706] For example, Order No. 1920 requires transmission providers to develop (and periodically update) multiple plausible and diverse Long-Term Scenarios based upon best available data, provides transmission providers with flexibility to develop evaluation processes, including selection criteria, that will enable them to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities, and lacks a selection mandate.

[707] *Infra* Stakeholder Process and Transparency section.

[708] We also note that the transparency requirements adopted herein, *see infra* Evaluation and Selection of Long-Term Regional Transmission Facilities, will provide states with additional insight into the efficiency and cost-effectiveness of any Long-Term

provides transmission providers with the tools and safeguards that they need to manage uncertainty and mitigate the risk of speculative regional transmission development while preserving the benefits of Long-Term Regional Transmission Planning.

242. For the same reason, we are unpersuaded by Alabama Commission's related argument that action on transmission plans should be determined at the state level to avoid costly transmission facilities that may not be needed. Nonetheless, as further discussed in this order, we clarify Order No. 1920 to require transmission providers to include and consider the perspective of Relevant State Entities in multiple ways, including: (1) to consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios; (2) to include any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities agree to in the transmittal or as an attachment to their compliance filings; (3) to consult with Relevant State Entities (a) prior to amending the *ex ante* Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) agreed to by Relevant State Entities or (b) if Relevant State Entities seek for a transmission provider to amend the method on file; (4) to develop a reasonable number of additional scenarios, when requested by Relevant State Entities, for the purposes of informing the application of Long-Term Regional Cost

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Regional Transmission Facilities that transmission providers select.

Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es); and (5) to make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of the allocated costs, by zone (i.e., by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of the benefits imputed to each zone, as such benefits can be reasonably estimated, when a cost allocation method is agreed upon under a State Agreement Process or, if no State Agreement Process is used, at the time the transmission provider selects the Long-Term Regional Transmission Facility. These additional measures to involve states will resolve Alabama Commission's concern and prevent costly transmission facilities that are not actually needed from being constructed.

243. As to another argument raised by Alabama Commission, which we interpret to argue that Long-Term Regional Transmission Planning should serve only to inform other transmission planning processes, we continue to find that remedying the deficiencies in the Commission's existing regional transmission planning requirements requires that transmission providers adopt the requirements herein, which will allow them to identify and have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs.[709]

244. We disagree with Dominion's argument that the Commission failed to address commenters' request for flexibility regarding the length of the minimum transmission planning horizon. The Commission has already justified its decision not to adopt a

[709] Order No. 1920, 187 FERC ¶ 61,068 at P 914.

shorter transmission planning horizon, reasoning that a planning horizon of less than 20 years would be insufficient to capture Long-Term Transmission Needs, develop and construct Long-Term Regional Transmission Facilities with long lead-time requirements, and compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.[710] The Commission explained why providing transmission providers with flexibility to choose a shorter transmission planning horizon would limit transmission providers' ability to adequately plan for Long-Term Transmission Needs and perpetuate the status quo, thus failing to address the deficiencies that the Commission identified in its existing regional transmission planning and cost allocation requirements.[711] Moreover, in adopting the 20-year minimum transmission planning horizon, the Commission struck a balance between, on the one hand, providing transmission providers with sufficient time to proactively identify Long-Term Transmission Needs and ultimately construct more efficient or cost-effective Long-Term Regional Transmission Facilities to meet those needs, and, on the

[710] *Id.* P 349.

[711] *See, e.g.*, *id.* PP 115-116 (finding that, under the status quo, most transmission planning regions do not plan beyond a 10-year transmission planning horizon, which prevents transmission providers from identifying Long-Term Transmission Needs and considering regional transmission facilities that may be more efficient or cost-effective solutions to address those needs and fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide).

other hand, avoiding uncertainty regarding system conditions and transmission needs beyond a 20-year horizon.[712]

245. Finally, we reiterate that, in this order, the Commission clarifies Order No. 1920 to increase the states' involvement in the Long-Term Transmission Planning Process to provide them with a greater role in determining Long-Term Transmission Needs, and ensuring that they are able to provide input into the method used to allocate the costs of Long-Term Regional Transmission Facilities.

246. For these reasons, we reject Dominion's request that the Commission allow PJM/Dominion Energy Virginia to continue to use a 15-year transmission planning horizon and South Carolina Regional Transmission Planning/Dominion Energy South Carolina to continue to use a 10-year transmission planning horizon.[713] Likewise, for these same reasons, we decline Ohio Commission Federal Advocate's request that the Commission clarify that Long-Term Scenarios resulting from a 20-year transmission planning horizon will be used for informational purposes only.

247. Further, we find unpersuasive Ohio Commission Federal Advocate's allegation that the Commission contravened the consumer-protection requirements of the FPA by adopting a 20-year minimum transmission planning horizon.[714] Ohio Commission Federal Advocate does not state how the 20-year minimum transmission planning

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[712] *Id.* P 345.

[713] *See* Dominion Rehearing Request at 12-13, 16.

[714] *See* Ohio Commission Federal Advocate Rehearing Request at 20.

horizon contravenes the FPA nor does it specify which requirements of the FPA the Commission allegedly transgressed by adopting the 20-year minimum transmission planning horizon requirement. To the extent that Ohio Commission Federal Advocate is claiming that the 20-year minimum transmission planning horizon requirement will result in unjust and unreasonable rates, as discussed above, we have provided a number of flexibilities to increase the states' involvement in Long-Term Regional Transmission Planning and to ensure that there is a significant degree of transparency in Long-Term Regional Transmission Planning, both of which will ensure that rates are just and reasonable. Recognizing these additional flexibilities, we continue to find the required 20-year minimum transmission planning horizon is integral to the requirement that transmission providers conduct long-term, forward-looking, and more comprehensive regional transmission planning.[715] The Commission found that such a requirement is necessary to remedy the deficiencies that it identified in its existing regional transmission planning and cost allocation requirements[716] and will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to Long-Term Transmission Needs, which will help ensure just and reasonable rates.[717]

[715] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 345, 349.

[716] *Id.* P 134.

[717] *See id.* PP 345, 349.

### 3. Frequency of Long-Term Scenario Revisions

#### a. Order No. 1920 Requirements

248. In Order No. 1920, the Commission modified the NOPR proposal and required transmission providers in each transmission planning region to reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years,[718] rather than at least every three years as the NOPR proposed.[719] The Commission explained that, in implementing this requirement, transmission providers in each transmission planning region must reassess whether the data inputs and factors incorporated in previously developed Long-Term Scenarios need to be updated and then revise those Long-Term Scenarios, as needed, to reflect updated data inputs and factors.[720] The Commission clarified that a Long-Term Regional Transmission Planning cycle, which begins with the development of Long-Term Scenarios using best available data inputs,[721] and proceeds to identifying Long-Term Transmission Needs, measuring the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluating and deciding whether to select Long-Term Regional Transmission Facilities, must conclude no later than five years after the

[718] *Id.* P 377.

[719] NOPR, 179 FERC ¶ 61,028 at P 97.

[720] Order No. 1920, 187 FERC ¶ 61,068 at P 377.

[721] At the outset of a Long-Term Regional Transmission Planning cycle, transmission providers may develop the new Long-Term Scenarios either by crafting entirely new Long-Term Scenarios or by updating the data inputs and factors for previously developed Long-Term Scenarios. *Id.*

date it began.[722] Transmission providers must complete these steps of the Long-Term Regional Transmission Planning cycle, including selection decisions, no later than three years from the date that the Long-Term Regional Transmission Planning cycle began.[723]

249. The Commission stated that nothing in Order No. 1920 prevents transmission providers from evaluating and selecting *additional* Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins.[724] However, the Commission explained that, if Long-Term Regional Transmission Facilities are selected at year three of the Long-Term Regional Transmission Planning cycle, those same Long-Term Regional Transmission Facilities cannot be de-selected during the remainder of the current five-year planning cycle.[725]

250. The Commission found that, while three years provides sufficient time for transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle,[726] requiring the Long-Term Regional Transmission Planning cycle to repeat at three-year intervals could be administratively burdensome and the benefit of updating Long-Term Scenarios every three years may not outweigh those additional

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[722] *Id.* P 378.

[723] *Id.* P 379.

[724] *Id.* P 379 n.873.

[725] *Id.*

[726] Order No. 1920, 187 FERC ¶ 61,068 at P 379 (citations omitted).

burdens.[727] Thus, the Commission found that requiring selection decisions to occur within three years of commencing a Long-Term Regional Transmission Planning cycle, while allowing as long as five years between the commencement of each planning cycle, strikes an appropriate balance between various benefits and burdens.[728] Order No. 1920 required that transmission providers conclude one Long-Term Regional Transmission Planning cycle before developing Long-Term Scenarios at the beginning of the next Long-Term Regional Transmission Planning cycle.[729]

251. Order No. 1920 also required transmission providers to designate a point in the evaluation process at which they will decide to either select or not select the relevant Long-Term Regional Transmission Facility (or portfolio of such Facilities) along with a point in time or action that concludes a Long-Term Regional Transmission Planning cycle.[730] The Commission further stated that transmission providers may propose on compliance to conduct Long-Term Regional Transmission Planning more frequently than every five years.[731]

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[727] *Id.* (citations omitted).

[728] *Id.*

[729] *Id.* P 381.

[730] *Id.*

[731] *Id.* P 384.

**b. Requests for Rehearing and Clarification**

252. PIOs request rehearing of the Commission's decision to extend the Long-Term Regional Transmission Planning Cycle from three years to five years. They request that the Commission reduce the Long-Term Regional Transmission Planning cycle to three years.[732] PIOs argue that the Commission's decision to extend the Long-Term Regional Transmission Planning cycle from three years, as it proposed in the NOPR, to five years lacked support in the record, was not based on the Commission's findings, and was arbitrary and capricious given the urgency of the problem.[733] PIOs assert that the faster transmission drivers change, the more frequently Long-Term Scenarios should be updated.[734] PIOs contend that, in decreasing the frequency of Long-Term Regional Transmission Planning cycles, the Commission disregarded evidence that transmission drivers—e.g., reliability concerns, demand, interconnection request capacity—have changed at an accelerating pace, since the issuance of the NOPR.[735]

253. PIOs aver that under Order No. 1920, transmission providers complete the entire substance of the planning cycle projects in the first three years, followed by a "fallow period" for up to two years.[736] This structure, PIOs argue, fails to alleviate the purported

[732] PIOs Rehearing Request at 9-15.

[733] *Id.* at 6 (citations omitted).

[734] *Id.* at 10-11.

[735] *Id.* at 9-11 (citations omitted).

[736] *Id.* at 11 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 378-379).

administrative burdens associated with the NOPR's three-year proposal and undermines Order No. 1920's essential purpose of requiring transmission providers to identify and address rapidly-shifting and critical regional transmission needs with urgency.[737] PIOs assert that it is illogical for the Commission to claim that transmission providers need two additional years at the end of each cycle to update model inputs in preparation for the next transmission planning cycle when they initially assembled that same information, from scratch, in three years.[738]

254. In support of their request that the Commission grant rehearing and adopt the NOPR's proposed three-year transmission planning cycle, PIOs also assert that the structure of the five-year planning structure is unclear. PIOs argue that Order No. 1920 nearly contradicts itself by stating that transmission providers must "determine whether to select Long-Term Regional Transmission Facilities no later than three years" after the cycle begins and then adding that "nothing in this final rule prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three" of the cycle and before the next cycle begins.[739] PIOs argue that, while these and similar statements are facially irreconcilable, they could be harmonized under a reading that would allow transmission providers to make final selection decisions on any Long-Term Regional Transmission Facilities up until the end

[737] *Id.* at 12.

[738] *Id.* at 12-13.

[739] *Id.* at 13 (quoting Order No. 1920, 187 FERC ¶ 61,068 at PP 379, 381).

of the five-year transmission planning cycle as long as they make a selection decision on at least one Long-Term Regional Transmission Facility before the end of year three.[740] According to PIOs, however, such a structure would undermine stakeholder concerns about changes to the planning process that occur mid-stream that would require re-running an analysis and would encourage transmission providers to make decisions when stakeholders are no longer at the table.[741] PIOs request that the Commission grant rehearing and adopt the NOPR's widely supported three-year transmission planning cycle.[742]

255. SERTP Sponsors request clarification as to what Order No. 1920 requires with respect to the inclusion of previously selected Long-Term Regional Transmission Facilities in updated base or reference cases that transmission providers use in the subsequent Long-Term Regional Transmission Planning cycle. SERTP Sponsors claim that Order No. 1920 may be inconsistent on this question because one section of the rule appears to require transmission providers to include such facilities in these updated base or reference cases while another section of the rule appears to provide flexibility on this issue.[743]

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[740] *Id.* at 14.

[741] *Id.* at 13-14.

[742] *Id.* at 15. PIOs also argue that, for the small minority of entities that need more initial flexibility beyond the one-year period entities already have to file compliance filings, the Commission could allow for case-by-case extensions. *Id.*

[743] SERTP Sponsors Rehearing Request at 26-27 (citing Order No. 1920, 187

### c. Commission Determination

256. We sustain the requirement that transmission providers in each transmission planning region reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years.[744] We disagree with PIOs that the decision to extend the Long-Term Regional Transmission Planning cycle from three years to five years lacked support in the record, was not based on the Commission's findings, and was arbitrary and capricious.

257. First, we are not persuaded by PIOs' argument that, by extending the Long-Term Regional Transmission Planning cycle, the Commission acted inconsistently with its findings in Order No. 1920 that transmission needs are changing at an increasingly rapid pace.[745] In Order No. 1920, the Commission addressed the pace at which transmission drivers are changing, finding that transmission providers must reassess and revise their Long-Term Scenarios at least once every five years to ensure that the Long-Term Scenarios accurately reflect factors that may change over the five-year time span, such as changes in technology, load forecasts, or federal, federally-recognized Tribal, state, or local laws.[746] While transmission needs, and the factors driving those needs, are indeed changing rapidly, PIOs provide insufficient and unconvincing support for their argument

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FERC ¶ 61,068 at PP 382, 1031).

[744] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 377.

[745] PIOs Rehearing Request at 9-11.

[746] Order No. 1920, 187 FERC ¶ 61,068 at P 380.

that a five-year Long-Term Regional Transmission Planning cycle is incapable of accounting for that pace of change. Further, we underscore that Order No. 1920 provides transmission providers with flexibility to address evolving transmission needs. For instance, nothing in Order No. 1920 prohibits transmission providers from updating the assumptions, inputs, and factors, used to inform Long-Term Scenarios during a Long-Term Regional Transmission Planning cycle,[747] and, to the extent that transmission providers believe that a shorter Long-Term Regional Transmission Planning cycle is necessary to account for the pace of change, they may propose on compliance to conduct Long-Term Regional Transmission Planning more frequently than every five years.[748]

258. Second, the Commission's decision to require that Long-Term Regional Transmission Planning cycles occur at least every five years was guided by comments in the record urging the Commission to address competing priorities, including: (1) ensuring timely identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities; (2) providing transmission providers with sufficient flexibility to address regional differences; and (3) limiting the

[747] *See id.* PP 380-381. We also note that, consistent with Order No. 890's transparency transmission planning principle, Order No. 1920 requires transmission providers in each transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs that they use to create each Long-Term Scenario. *See id.* P 560 (citing Order No. 890, 118 FERC ¶ 61,119 at P 471).

[748] *See id.* P 384.

administrative burdens placed on transmission providers.[749] Order No. 1920's requirement that transmission providers reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years strikes a reasonable balance between those priorities. Further, we disagree with PIOs' assertion that extending the Long-Term Regional Transmission Planning cycle from three years to five years does not ease administrative burdens or improve planning accuracy.[750] In Order No. 1920, the Commission decreased the frequency at which Long-Term Regional Transmission Planning cycles must occur, meaning that transmission providers have the option to develop fewer Long-Term Scenarios over a five-year period than they would have been required to develop under the NOPR proposal, thus decreasing the administrative burden associated with updating the Long-Term Scenarios that form the basis for Long-Term Regional Planning during each planning cycle.

259. Third, we are not persuaded by PIOs' argument that the structure of the Long-Term Regional Transmission Planning cycle is unclear or that its implementation will exclude meaningful stakeholder participation.[751] Order No. 1920 requires transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle and make selection decisions no later than three years from the date when the Long-Term

[749] *See id.* P 379.

[750] PIOs Rehearing Request at 12-13.

[751] *Id.* at 13-15.

Regional Transmission Planning cycle began.[752] To the extent that transmission providers decide to evaluate additional Long-Term Regional Transmission Facilities after year three but before the next Long-Term Regional Transmission Planning cycle begins, Order No. 1920 gives them the flexibility to do so.[753] One possible outcome of this structure is that transmission providers may make selection decisions on additional Long-Term Regional Transmission Facilities until the end of the five-year Long-Term Regional Transmission Planning cycle. But we disagree with PIOs' contention that Order No. 1920 could be read to allow transmission providers to make "final" selection decisions on "*any*" Long-Term Regional Transmission Facilities until the five-year Long-Term Regional Transmission Planning cycle's end so long as they make a selection decision on at least one Long-Term Regional Transmission Facility before the end of year three.[754]

260. Order No. 1920 requires that transmission providers complete their evaluation and selection processes in the first three years of a Long-Term Regional Transmission Planning cycle, including identifying Long-Term Regional Transmission Facilities that address the Long-Term Transmission Needs that transmission providers identified, estimating the costs and measuring the benefits of those facilities, and making a selection decision on those facilities, including a determination that is sufficiently detailed for

[752] Order No. 1920, 187 FERC ¶ 61,068 at PP 379, 955.

[753] *Id.* P 379 n.873.

[754] PIOs Rehearing Request at 14.

stakeholders to understand why particular facilities or portfolios of facilities were selected or not selected.[755] After transmission providers have completed these steps, no later than three years after the beginning of the Long-Term Regional Transmission Planning cycle, transmission providers may select "*additional*" Long-Term Regional Transmission Facilities, but they may not deselect any Long-Term Regional Transmission Facilities selected earlier in that Long-Term Regional Transmission Planning cycle.[756]

261. We therefore disagree with PIOs' argument that the five-year structure of the Long-Term Regional Transmission Planning cycle would encourage transmission providers to make planning decisions when stakeholders are "no longer at the table."[757] Such arguments are predicated on a misunderstanding of what Order No. 1920 requires. We emphasize that any Long-Term Regional Transmission Facilities selected after year three of the Long-Term Regional Transmission Planning cycle are selected in the Long-Term Regional Transmission Planning process. Thus, contrary to PIOs' suggestion, the requirements for selecting Long-Term Regional Facilities apply, including the transparency requirements adopted in Order No. 1920, should transmission providers

[755] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 955.

[756] *Id.* P 379 n.873

[757] PIOs Rehearing Request at 14.

choose to evaluate and select additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle.[758]

262. Finally, we provide clarification to SERTP Sponsors as to the inclusion of previously selected Long-Term Regional Transmission Facilities in the updated base or reference cases that transmission providers will use in subsequent Long-Term Regional Transmission Planning cycles. In most circumstances, we expect that transmission providers will include previously selected Long-Term Regional Transmission Facilities, including those that are not yet in service, in these updated planning models, and we continue to find that doing so will improve the accuracy of Long-Term Regional Transmission Planning.[759] We expect that if transmission providers conclude that previously-selected Long-Term Regional Transmission Facilities are not appropriate to use in a base case, they would provide an explanation to stakeholders who may be relying on the base case in future transmission planning or generator interconnection studies as to why these facilities are not included. Nevertheless, we clarify that Order No. 1920 does not *require* that transmission providers include previously selected Long-Term Regional Transmission Facilities in the planning models that they use in a subsequent Long-Term Regional Transmission Planning cycle, and we continue to find that it is appropriate to provide flexibility to transmission providers on how they update their planning models.[760]

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[758] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 954.

[759] *See id.* P 382.

[760] *See id.* P 1031.

#### 4. Categories of Factors

##### a. Requirement to Incorporate Categories of Factors

###### i. Order No. 1920 Requirements

263. In Order No. 1920, the Commission required transmission providers in each transmission planning region to incorporate in the development of Long-Term Scenarios seven specific categories of factors: (1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[761] The Commission found that incorporating these categories of factors in the development of Long-Term Scenarios is necessary because these categories are essential to identifying Long-Term Transmission Needs, and that incorporating them will ensure that transmission providers are accounting for known and identifiable drivers of Long-Term Transmission Needs.[762] The Commission stated that transmission

[761] *Id.* P 409.

[762] *Id.* P 410.

providers may not exclude any of the proposed categories of factors from the development of Long-Term Scenarios because each category of factors includes important drivers of Long-Term Transmission Needs, and that not incorporating all of the categories of factors will increase the likelihood that transmission providers will continue to underestimate or omit certain drivers of Long-Term Transmission Needs.[763]

264. The Commission explained that incorporating a category of factors in the development of Long-Term Scenarios requires transmission providers to use factors in the category, for each factor individually or collectively, to determine the assumptions that will be used in the development of Long-Term Scenarios.[764] The Commission stated that it expects that similar factors (or groups of factors) affecting a single assumption used in the development of Long-Term Scenarios will have an additive effect on that assumption.[765] Further, transmission providers must incorporate the categories of factors in the development of Long-Term Scenarios in a way that results in plausible and diverse Long-Term Scenarios.[766]

265. With respect to factors within each category of factors, Order No. 1920 requires that transmission providers account for the factors that they have determined are likely to affect Long-Term Transmission Needs. Order No. 1920 further requires transmission

[763] *Id.* P 411.

[764] *Id.* P 413.

[765] *Id.*

[766] *Id.* P 414.

providers, in coordination with stakeholders through an open and transparent process, to determine how each of those factors (or group of similar factors) is likely to affect Long-Term Transmission Needs. Transmission providers must then account for the factors that they have determined are likely to affect Long-Term Transmission Needs in the development of Long-Term Scenarios but need not account for a factor that they determine is unlikely to affect Long-Term Transmission Needs.[767]

266. The Commission stated that requiring transmission providers to incorporate the seven categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility.[768] The Commission also stated that the final rule does not direct the development of specific transmission facilities because transmission providers retain discretion to determine how specific factors will affect Long-Term Transmission Needs.[769]

**ii. Requests for Rehearing and Clarification**

267. Arizona Commission argues that Order No. 1920's requirement that transmission providers use a specific set of "planning criteria," i.e., that transmission providers incorporate seven categories of factors in Long-Term Scenarios, is "simply a way of 'pre-cooking' outcomes."[770] Arizona Commission argues that this is inconsistent with the

[767] *Id.* P 415.

[768] *Id.* P 417.

[769] *Id.* P 419.

[770] Arizona Commission Rehearing Request at 18.

NOPR, which required transmission providers to implement a process, not achieve specific outcomes.[771]

268. SERTP Sponsors request that the Commission clarify or, in the alternative, grant rehearing to specify that Order No. 1920 does not require each factor to have an additive effect on a common assumption because, in their view, such a requirement would be arbitrary and capricious and not supported by substantial evidence.[772] SERTP Sponsors assert that requiring each factor to have an additive effect would undermine transmission providers' discretion over how to account for different factors.[773]

269. Further, SERTP Sponsors argue that the record does not demonstrate that each individual factor will have an additive effect, and a finding to this effect risks overstating the effect of each factor, which would render the resulting scenarios implausible and more likely to misidentify Long-Term Transmission Needs and Facilities.[774]

270. Designated Retail Regulators and Undersigned States request that the Commission grant rehearing on the grounds that the Order No. 1920 requirement to use the seven categories of factors in Long Term Regional Transmission Planning will overvalue transmission benefits and will result in unjust, unreasonable, and unduly discriminatory

[771] *Id.*

[772] SERTP Sponsors Rehearing Request at 12-13.

[773] *Id.* at 13.

[774] *Id.*

rates.[775] Designated Retail Regulators and Undersigned States argue that transmission planning assumptions should reflect regional differences, and that requiring transmission providers to develop Long-Term Scenarios that incorporate Order No. 1920's seven categories of factors will result in unjust and unreasonable rates because the categories of factors overlap and may result in double counting.[776] Designated Retail Regulators and Undersigned States also assert that there is insufficient evidence and analysis to conclude that use of the factors will result in cost-effective solutions.[777]

### iii. Commission Determination

271. Regarding Arizona Commission's argument that Order No. 1920's requirement that transmission providers incorporate seven categories of factors into their development of Long-Term Scenarios predetermines outcomes in Long-Term Regional Transmission Planning, we reiterate that, in Order No. 1920, as clarified herein, the Commission gives transmission providers the tools necessary to respond to changing factors that drive Long-Term Transmission Needs.[778] As discussed below in further detail,[779] transmission providers must consult with and consider the positions of the Relevant State Entities and

[775] Designated Retail Regulators Rehearing Request at 8, 26; Undersigned States Rehearing Request at 8, 26.

[776] Designated Retail Regulators Rehearing Request at 8, 26-29; Undersigned States Rehearing Request at 8, 26-29.

[777] Designated Retail Regulators Rehearing Request at 8; Undersigned States Rehearing Request at 8.

[778] Order No. 1920, 187 FERC ¶ 61,068 at P 233.

[779] *Infra* Stakeholder Process and Transparency section.

any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios. The Commission also explained in both the NOPR and in Order No. 1920 that it is not requiring that transmission providers achieve any particular outcome via Long-Term Regional Transmission Planning,[780] and Order No. 1920 does not mandate selection of any Long-Term Regional Transmission Facilities.[781]

272. In response to SERTP Sponsors' request for clarification, we clarify that Order No. 1920 does not require transmission providers, when determining the assumptions that they will use when developing Long-Term Scenarios where similar factors (or groups of factors) affect a single assumption, to assume that the factors have additive effects on the relevant assumptions. The Commission stated in Order No. 1920 that it expected that similar factors (or groups of factors) affecting a single assumption used in the development of Long-Term Scenarios will have an additive effect on that assumption,[782] but we agree with SERTP Sponsors that this may not always be the case, and at times, similar factors may not have an additive effect on assumptions used to develop Long-

[780] *See, e.g.*, NOPR, 179 FERC ¶ 61,028 at PP 9, 245; Order No. 1920, 187 FERC ¶ 61,068 at PP 232, 266.

[781] Order No. 1920, 187 FERC ¶ 61,068 at PP 1026-1027.

[782] *Id.* P 413.

Term Scenarios. We also acknowledge that factors in different categories of factors may overlap.[783]

273. We clarify that, where factors may have overlapping effects on the planning assumptions, transmission providers must avoid double counting the effect that those factors have on assumptions used to develop Long-Term Scenarios. Specifically, where there is overlap between factors in Factor Categories One through Three and factors in Factor Categories Four through Seven, or a factor could arguably be considered in a Factor Category in the first three categories or the last four categories, transmission providers must incorporate that factor in the appropriate Factor Category in the first three categories.[784] Because Relevant State Entities and their designated representatives will participate in developing Long-Term Scenarios by informing how transmission providers account for the impact of individual factors, we believe that Relevant State Entities, working in concert with transmission providers, will be able to identify and minimize instances where factors overlap. Further, to the extent that factors in Factor Categories

[783] *Id.* P 440 ("We acknowledge that there could be overlap between Factor Categories One and Two because a certain law or regulation could reasonably be considered to fit into both categories. In such a circumstance, transmission providers must account for the law or regulation in one of the two categories, not both, to avoid double-counting of that factor's anticipated effect on Long-Term Transmission Needs."). As another example, a utility commitment in Factor Category Seven would overlap with an integrated resource plan if the utility commitment was incorporated in the development of the integrated resource plan.

[784] For example, if a transmission provider determines that a factor will affect Long-Term Transmission Needs, but the factor could arguably be incorporated in Factor Category Three or Factor Category Seven, the transmission provider must incorporate this factor in Factor Category Three.

One through Three have overlapping effects on planning assumptions, transmission providers must ensure that each Long-Term Scenario accounts for the factors in Factor Categories One through Three without double counting their effects on planning assumptions. Finally, although we agree with SERTP Sponsors that similar factors will not always have an additive effect on assumptions used to develop Long-Term Scenarios, where similar factors do not overlap, we clarify our expectation that similar factors (or groups of factors) affecting certain assumptions used in the development of Long-Term Scenarios will have a combined effect on those assumptions accordingly.

274. In response to SERTP Sponsors' argument that the requirements in Order No. 1920 risk overstating the effect of each factor, which would render the resulting scenarios implausible and more likely to misidentify Long-Term Transmission Needs, we explain that Order No. 1920 addresses this issue by allowing transmission providers to exercise discretion in how they account for each factor, provided that each Long-Term Scenario account for and be consistent with factors in the first three categories of factors.[785] As the Commission noted in Order No. 1920, incorporating a category of factors into the development of Long-Term Scenarios does not require exacting precision; transmission providers may generalize how all of the discrete factors in a category of factors will, in the aggregate, affect the development of Long-Term

[785] It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

Scenarios.[786] In addition, the Commission held in Order No. 1920 that transmission providers have the discretion to determine whether specific factors must be accounted for within each category, how to account for specific factors in the development of Long-Term Scenarios, and how to vary the treatment of each category of factors across Long-Term Scenarios, provided that transmission providers assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities that transmission providers have determined are likely to affect Long-Term Transmission Needs are fully met.[787] Finally, we believe that the clarification discussed below will mitigate SERTP Sponsors' concern by ensuring that the effects of factors used to develop Long-Term Scenarios are not overstated.

275. More specifically, Order No. 1920 states that transmission providers must give states and stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate in Long-Term Scenarios, including how specific factors may affect Long-Term Transmission Needs.[788] We clarify below that, when incorporating planning for states' laws, policies, and regulations' into the development of Long-Term Scenarios, transmission providers must consult with and consider the positions of the Relevant State Entities and their designated representatives as to how

[786] Order No. 1920, 187 FERC ¶ 61,068 at P 413.

[787] *Id.* P 417.

[788] *Id.* P 528.

those requirements will be realized.[789] If, for example, states have laws regarding the future resource mix or decarbonization targets, the assumptions for how the power industry would need to evolve to meet those legal requirements should be developed in close consultation with the Relevant State Entities. We clarify that, for a state that has required integrated resource planning processes, transmission providers should include one of the state's preferred power system trajectories, including both the supply and demand side resource trajectory as appropriate, in each Long-Term Scenario, or include different state-preferred power system trajectories in different Long-Term Scenarios.

276. While we disagree with the rehearing arguments of Designated Retail Regulators and Undersigned States that the Order No. 1920 requirement to use the seven categories of factors in Long Term Regional Transmission Planning will result in overvaluing transmission benefits, we believe that the clarifications discussed herein will alleviate the concerns underlying their rehearing arguments. As an initial matter, we find arguments that the categories of factors overlap to be moot because, as clarified above, transmission providers should avoid double counting the effects of overlapping factors when developing Long-Term Scenarios. While these rehearing parties are correct that Order No. 1920 requires transmission providers to incorporate seven categories of factors, transmission providers retain specific discretion with respect to how they account for each individual factor within a category to develop the required Long-Term Scenarios.[790]

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[789] *Infra* Stakeholder Process and Transparency section.

[790] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 412 (allowing transmission providers to propose to use additional categories of factors); *id.* P 413 (clarifying that

Further, as discussed below,[791] we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios, which will ensure that states have input into these factors and that these factors are not over or undervalued. We further note the Commission's finding in Order No. 1920 that transmission providers have discretion to reflect regional differences in the development of Long-Term Scenarios.[792]

277. We disagree with Designated Retail Regulators and with Undersigned States that Order No. 1920 provides insufficient evidence and analysis to conclude that use of the factors will result in cost-effective solutions. As discussed above and below, we, in this order, adopt a number of clarifications to ensure that states are consulted regarding the use of factors to develop Long-Term Scenarios, which, in turn, affect which Long-Term Regional Transmission Facilities are selected. We also emphasize that the states have a

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incorporating categories of factors does not require exacting precision and allowing transmission providers to generalize how factors within the categories will, in the aggregate, affect the development of Long-Term Scenarios); *id.* P 415 (allowing transmission providers to determine whether specific factors will affect Long-Term Transmission Needs and allowing transmission providers not to account for specific factors that they determine do not affect such needs); *id.* P 417 (allowing transmission providers to determine how to account for specific factors within different Long-Term Scenarios).

[791] *Infra* Stakeholder Process and Transparency section.

[792] Order No. 1920, 187 FERC ¶ 61,068 at P 417.

significant role in working to create a cost allocation method that ensures any solutions that are selected have costs allocated appropriately to beneficiaries. Because of this involvement, we find that the potential risk of the categories of factors leading to solutions that are not cost-effective is diminished, particularly in light of the requirement that selection criteria used in Long-Term Regional Transmission Planning must seek to maximize benefits accounting for costs over time without over-building transmission facilities.[793] Finally, we add that Order No. 1920 included substantial evidence in the record to demonstrate that existing transmission planning and cost allocation processes were insufficient to ensure just and reasonable rates by inadequately accounting on a forward-looking basis for known determinants of Long-Term Transmission Needs.[794]

### b. Specific Categories of Factors and the Treatment of Factors in the Development of Long-Term Scenarios

#### i. Order No. 1920 Requirements

278. As stated above, in Order No. 1920, the Commission found that incorporating the seven categories of factors in the development of Long-Term Scenarios was necessary. The Commission stated that transmission providers may not exclude any of the categories of factors from being incorporated into the development of Long-Term Scenarios because each category includes important determinants of Long-Term Transmission Needs, and failing to incorporate all of the proposed categories of factors into Long-Term Scenarios

[793] *Id.* P 964.

[794] *Id.* PP 112-133.

would increase the likelihood that transmission providers would continue to underestimate or omit known determinants of Long-Term Transmission Needs.[795] The Commission considered category-specific record evidence in support of its determination to adopt each of the seven categories of factors.[796] The Commission declined to adopt additional categories of factors proposed by commenters because of a lack of substantial record evidence, or a finding that the commenter-proposed category of factors is already accounted for in other parts of Long-Term Regional Transmission Planning.[797]

279. The Commission in Order No. 1920 also required transmission providers in each transmission planning region to assume that legally binding obligations (i.e., federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met.[798] The Commission therefore required each Long-Term Scenario to account for and be consistent with, and not discount, factors in the first three categories of factors (i.e., (1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and

[795] *Id.* P 411.

[796] Order No. 1920, 187 FERC ¶ 61,068 at PP 448-449, 457-458, 464-466, 472-473, 481-484.

[797] *Id.* PP 492-494.

[798] *Id.* P 507.

electrification; and (3) state-approved integrated resource plans and expected supply obligations for load-serving entities) once transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs. The Commission found that it is necessary to prohibit the discounting of factors in the first three categories of factors because they are more certain drivers of Long-Term Transmission Needs, relative to factors in other Factor Categories.[799] Where two legally binding factors have conflicting or opposite implications for Long-Term Transmission Needs, however, transmission providers must reconcile this information while giving full effect to the maximum extent possible to all legally binding factors.[800]

280. The Commission allowed transmission providers to rely on the open and transparent stakeholder process discussed below to identify the factors in the first three required categories of factors. Transmission providers may independently identify factors in the first three categories of factors, but Order No. 1920 does not obligate transmission providers to do so.[801] Transmission providers retain the discretion to determine whether and how particular factors, including those in the first three categories of factors, are likely to affect Long-Term Transmission Needs.[802] Further, the Commission stated in Order No. 1920 that it expects that transmission providers will rely,

[799] *Id.*

[800] *Id.* P 515.

[801] *Id.* P 508.

[802] *Id.* PP 510, 512.

at least in part, on information that relevant federal, state, and local government entities, federally-recognized Tribes, utilities, and load-serving entities provide during the required open and transparent stakeholder process to determine if specific factors are likely to affect Long-Term Transmission Needs and how to account for those specific factors in Long-Term Scenarios.[803]

281. The Commission provided transmission providers with additional discretion in how they account for each factor in Factor Categories Four through Seven (i.e., (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs) compared to how they account for each factor in the first three categories. For purposes of developing plausible and diverse Long-Term Scenarios, Order No. 1920 requires transmission providers, after they have determined that a specific factor in Factor Categories Four through Seven is likely to affect Long-Term Transmission Needs over the transmission planning horizon, to assess the extent to which the anticipated effects on Long-Term Transmission Needs due to that factor are likely to be realized in part, in full, or exceeded.[804] Transmission providers may choose to discount or to put more weight on the effects of factors in Factor

[803] *Id.* P 511.

[804] *Id.* P 516.

Categories Four through Seven on Long-Term Transmission Needs, but only to the extent that each Long-Term Scenario remains plausible.[805]

282. The Commission disagreed with concerns that the additional flexibility afforded to transmission providers in how they account for each factor in Factor Categories Four through Seven could allow transmission providers to ignore these categories of factors. The Commission explained that Order No. 1920 requires transmission providers to incorporate all categories of factors in each Long-Term Scenario, even if they discount specific factors within the category, and requires all Long-Term Scenarios to be plausible.[806]

283. Further, the Commission explained that, because Order No. 1920 requires that all Long-Term Scenarios be consistent with and fully account for factors in Factor Category Three, which includes state-approved integrated resource plans and expected supply obligations of load-serving entities, the final rule does not ignore the Commission's fundamental responsibility under FPA section 217 to facilitate planning to meet the needs of load-serving entities.[807]

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[805] *Id.* P 518.

[806] *Id.*

[807] *Id.* P 420.

### ii. Requests to Omit One or More Specific Categories of Factors

#### (a) Requests for Rehearing and Clarification

284. Designated Retail Regulators and Undersigned States request that the Commission grant rehearing on the grounds that Order No. 1920 requires transmission providers to consider several factors in Long-Term Regional Transmission Planning, and including these factors will result in rates that are unjust and unreasonable.[808] Arizona Commission avers that through Order No. 1920, the Commission is promoting certain preferred "green" energy generation resources by requiring transmission providers to incorporate seven categories of factors.[809] Arizona Commission states that these factors have political and policy considerations that do not belong in Arizona where the legislature has not mandated such costs, planning, or experimentation to the detriment of ratepayers.[810]

285. Designated Retail Regulators and Undersigned States both argue that Order No. 1920 usurps the role of the states in transmission planning by requiring that the plans and goals of some states, tribes, local governments, and private companies override the plans and goals of other entities while also forcing these entities to bear the cost burden.[811] Designated Retail Regulators and Undersigned States assert that Factor

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[808] Designated Retail Regulators Rehearing Request at 7; Undersigned States Rehearing Request at 7.

[809] Arizona Commission Rehearing Request at 15.

[810] *Id.* at 22.

[811] Designated Retail Regulators Rehearing Request at 8; Undersigned States

Categories One, Two, Four, Six, and Seven unjustly involve the policy goals of state and local governments and the commitments of utilities, and thus impose construction costs upon ratepaying loads without sufficient and measurable benefits.[812] Designated Retail Regulators and Undersigned States both state that there is insufficient evidence and analysis to support that use of these factors will result in cost-effective solutions.[813]

286. Ohio Commission Federal Advocate requests that the Commission grant rehearing on the grounds that the Commission acted arbitrarily and capriciously and abused its discretion because Order No. 1920 requires transmission providers to incorporate unreasonable categories of factors in the development of Long-Term Scenarios.[814] Specifically, Ohio Commission Federal Advocate is concerned that several factors would encourage a massive transmission build-out at unjust and unreasonable rates and requests that the Commission grant rehearing to remove Factor Categories One, Two, Six, and Seven as these factors are highly speculative and subject to change.[815] Ohio Commission Federal Advocate asserts that the Commission has not engaged in reasoned decision making by asserting that a best-available-data requirement will ensure these factors are

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Rehearing Request at 7-8.

[812] Designated Retail Regulators Rehearing Request at 28; Undersigned States Rehearing Request at 27-28.

[813] Designated Retail Regulators Rehearing Request at 8 (citation omitted); Undersigned States Rehearing Request at 8 (citation omitted).

[814] Ohio Commission Federal Advocate Rehearing Request at 15.

[815] *Id.* at 16-17.

incorporated in a meaningful way because even the best available data for a corporate commitment still amounts to nothing more than a corporate commitment.[816] Ohio Commission Federal Advocate claims that the Commission's attempt to mitigate the flaws of requiring transmission providers to incorporate factors in Factor Categories Four through Seven by allowing transmission providers to discount or give special weight to these factors is arbitrary and capricious. Further, Ohio Commission Federal Advocate asserts that Factor Categories Three, Four, and Five may be problematic if transmission projects are chosen to satisfy state or federal policies and, due to the other provisions of Order No. 1920, may not be properly cost allocated.[817]

287. Several petitioners request that the Commission grant rehearing on the grounds that the Order No. 1920 requirement to include Factor Category Seven (utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect long-term transmission needs) should be excluded from the development of Long-Term Scenarios.[818]

288. SERTP Sponsors argue that Factor Category Seven does not demonstrate reasoned decision making, is not supported by substantial evidence, and could intrude into matters

[816] *Id.* at 17.

[817] *Id.*

[818] Alabama Commission Rehearing Request at 4-5; Industrial Customers Rehearing Request at 49-54; Northern Virginia Rehearing Request at 4-7; NRECA Rehearing Request at 55; SERTP Sponsors Rehearing Request at 15-17; Virginia and North Carolina Commissions Rehearing Request at 6-8.

involving retail customers subject to state regulation in an unduly discriminatory and preferential manner.[819] SERTP Sponsors assert that utility or corporate commitments and local policy goals are fundamentally retail concerns with arrangements subject to state-regulated tariffs and proceedings, and that the other categories of factors already encompass the transmission needs from these arrangements.[820] SERTP Sponsors also request clarification that Factor Category Seven is not intended to give preferential treatment to certain retail customers, like corporations, over others.[821]

289. Industrial Customers state that the Commission did not satisfactorily explain in Order No. 1920 why it found unpersuasive comments on the NOPR questioning the inclusion of utility or corporate commitments in Factor Category Seven, given that such commitments may not be firm or could change over the transmission planning horizon.[822] Further, Industrial Customers assert that the Commission's attempt to alleviate concerns by emphasizing in Order No. 1920 that transmission providers "have discretion" to account for ambiguity concerning these commitments actually raises several additional issues.[823] Industrial Customers argue that there are no clear rules to guide such discretion and that there is an alleged contradiction with Order No. 1920's "earlier mandate to use

[819] SERTP Sponsors Rehearing Request at 16 (citations omitted).

[820] *Id.* at 15.

[821] *Id.* at 16.

[822] Industrial Customers Rehearing Request at 51 (citation omitted).

[823] *Id.* at 51-52 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 484).

publicly available information on *goals* and aspirations around corporate energy purchasing strategies."[824] Industrial Customers add that one transmission provider, PJM, has publicly stated that it does not want such discretion due to the significant administrative burdens.[825]

290. Industrial Customers additionally state that Order No. 1920's inclusion of Factor Category Seven unduly discriminates against load that may be served by generation that may not be considered "clean energy."[826] Industrial Customers highlight the Commission's statement that Order No. 1920 responds to "corporate, governmental, and utility commitments to rely on *certain* generation resources" and argue that the word "certain" implies without definition or justification a limited subset within possible generation resources.[827]

291. Industrial Customers contend that many companies consider corporate sustainability and clean energy strategies to be proprietary and sensitive, so utilizing known and available corporate commitments and information without also having the underpinning analytical evidence cannot be reasonably relied on to inform future transmission planning scenarios.[828] Similarly, Industrial Customers state that Order

[824] *Id.* at 52 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 413).

[825] *Id.* at 52-53 (citing PJM NOPR Initial Comments at 68).

[826] *Id.* at 54-55 (citations omitted).

[827] *Id.* at 55 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 261).

[828] *Id.* at 49-50.

No. 1920 does not demonstrate that corporate strategies and goals are known determinants or representative and reliable anecdotes able to be utilized in Long-Term Scenarios.[829]

292. Northern Virginia argues that the inclusion of "corporate commitments" as an independent factor in Category Factor Seven is arbitrary and capricious as this inclusion circumvents the planning process utilized by load serving utilities and state regulators to also meet these commitments.[830] Additionally, Northern Virginia states that corporate commitments are too ephemeral and uncertain to be included in Long-Term Scenarios, and asserts that transmission planning processes should utilize best data from utilities and state regulators that are required to plan to serve load.[831] Northern Virginia also argues that the Commission should not give special status to private corporations not charged with planning for the greater good, and that corporate commitments are not comparable to utility planning or governmental policy goals.[832] Northern Virginia states that any entities with corporate commitments can participate in existing stakeholder and customer processes.[833]

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[829] *Id.* at 50.

[830] Northern Virginia Rehearing Request at 4.

[831] *Id.* at 3-4.

[832] *Id.* at 4.

[833] *Id.* at 7-9.

293. Virginia and North Carolina Commissions argue that the Commission should remove Factory Category Seven from the development of Long-Term Scenarios as transmission providers may not have the resources and should not be in a position to assess the reasonableness or accuracy of corporate or utility commitments.[834] Similarly, Virginia and North Carolina Commissions contend that it would be unreasonable to expect state entities to use their limited resources to evaluate and opine on such commitments or policy goals and that many states may be constrained from doing so if these commitments impact filings before the state entity.[835] Additionally, Virginia and North Carolina Commissions request that the Commission only permit the incorporation of public policy goals previously approved through a state regulatory process or, alternatively, clarify that transmission providers can fully discount any public policy factors that fall under Factor Category Seven.[836]

294. NRECA states that the Commission expanded the concept of Long-Term Transmission Needs well beyond reliability, economic, and public policy issues by adopting seven categories of factors, including Factor Category Seven.[837] NRECA

[834] Virginia and North Carolina Commissions Rehearing Request at 7.

[835] *Id.*

[836] *Id.* at 8 (citation omitted).

[837] NRECA Rehearing Request at 54-55.

asserts that the costs of facilities built to satisfy corporate commitments should be borne by the relevant corporations, not by those who do not benefit from the facility.[838]

295. Harvard ELI and PIOs request clarification to reframe Factor Category Seven.[839] Harvard ELI requests that the Commission clarify whether Factor Category Seven implements the existing requirement to plan for all transmission users on a comparable basis and further clarify that all long-term planning rules are similarly rooted in the open access comparability standard.[840] PIOs request clarification on whether required scenario factors additionally include city and consumer-side market preferences.[841]

**(b) Commission Determination**

296. We are unpersuaded by parties that request that the Commission set aside the requirement for transmission providers to incorporate the seven specified categories of factors into the development of Long-Term Scenarios, including requests to set aside the requirement to incorporate certain specific categories of factors. Nevertheless, we believe certain clarifications adopted herein will alleviate the concerns these parties raise on rehearing. Specifically, our clarification that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to

[838] *Id.* at 55.

[839] Harvard ELI Rehearing Request at 9-11; PIOs Rehearing Request at 61.

[840] Harvard ELI Rehearing Request at 9-11.

[841] PIOs Rehearing Request at 61.

states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios will help ensure that each Long-Term Scenario reflects states' preferences and future needs. However, with respect to Factor Category Seven, we set aside the requirement to include corporate commitments, as discussed further below.

297. We continue to find that existing regional transmission planning requirements fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs. We reiterate that requiring transmission providers to incorporate the seven categories of factors into the development of Long-Term Scenarios is necessary because without doing so, transmission providers will fail to adequately consider drivers of Long-Term Transmission Needs.[842]

298. With regard to Arizona Commission's claim that Order No. 1920 favors "green" energy,[843] we reiterate that nothing in Order No. 1920 favors, promotes, or subsidizes particular types of generation resources over others and that the Commission's policies are technology and fuel neutral. Order No. 1920 does not endorse the merits of any laws and regulations or of any specific state-approved integrated resource plans.[844] Rather, we reiterate that states play a vital role in identifying the factors, especially in Factor Categories One, Two, and Seven, that transmission providers account for in Long-Term

[842] Order No. 1920, 187 FERC ¶ 61,068 at P 410.

[843] Arizona Commission Rehearing Request at 15.

[844] Order No. 1920, 187 FERC ¶ 61,068 at PP 232, 437.

Regional Transmission Planning. We are unpersuaded by Arizona Commission and NRECA that the categories of factors requirements in Order No. 1920 include policy factors that have not been previously considered in regional transmission planning.[845] In Order No. 1000, the Commission required transmission providers to establish procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[846]

299. We are not persuaded by arguments that Factor Category One and Factor Category Two, which include state and local laws and regulations, will unjustly impose the policy goals of certain state and local governments on others.[847] We reiterate that transmission planning of any kind will inherently reflect the policy choices of multiple decisionmakers because the quantity and location of generation and load are shaped by multiple decisionmakers.[848] In this case, we expect transmission providers to work with states to ensure the way those state laws and regulations are incorporated into Long-Term Scenarios reflects states' preferred implementation of those laws and regulations. We also reiterate that transmission providers must appropriately value the effect of states'

[845] Arizona Commission Rehearing Request at 22; NRECA Rehearing Request at 54-55.

[846] Order No. 1000, 136 FERC ¶ 61,051 at P 203; *see also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 89-92 (upholding this Order No. 1000 requirement).

[847] *E.g.*, Designated Retail Regulators Rehearing Request at 28; Ohio Commission Federal Advocate Rehearing Request at 16-17; Undersigned States Rehearing Request at 27-28.

[848] Order No. 1920, 187 FERC ¶ 61,068 at P 435.

policy decisions in regional transmission planning in order to ensure just and reasonable rates.[849]

300. Parties argue that the Commission's categories of factors requirements will impose formidable costs upon ratepaying loads that neither caused the need for the construction of additional transmission facilities nor measurably benefit from that construction and therefore are unjust and unreasonable and unduly discriminatory and preferential.[850] We disagree. The requirements of Order No. 1920, as clarified herein, ensure that Relevant States Entities, which represent consumers, have a voice in how factors within the categories of factors are accounted for, the development of Long-Term Scenarios that results from those factors, and the allocation of costs after a Long-Term Regional Transmission Facility is selected.[851] Nothing in Order No. 1920 changed the Commission's policy that costs must be allocated in a manner that is at least roughly commensurate with benefits, which ensures that ratepayers are not paying unjust and unreasonable rates.[852]

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[849] *Id.* P 436.

[850] *E.g.*, Designated Retail Regulators Rehearing Request at 28; Ohio Commission Federal Advocate Rehearing Request at 16-17; Undersigned States Rehearing Request at 27-28.

[851] *See infra* Stakeholder Process and Transparency section; Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section.

[852] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at PP 419, 1419, 1471, 1513.

301. We also disagree with arguments from Designated Retail Regulators and Undersigned States that there is insufficient evidence and analysis to support the conclusion that use of Factor Categories One, Two, Four, Six, and Seven will result in cost-effective solutions.[853] We believe the collaboration between transmission providers and Relevant State Entities, where relevant, will ensure that those categories of factors are incorporated into the development of Long-Term Scenarios that identify Long-Term Regional Transmission Facilities that both meet the needs of states and provide reliability and economic value. At the same time, we believe that transmission providers cannot identify more efficient or cost-effective solutions to Long-Term Transmission Needs if they undervalue or entirely omit the consideration of some or all of the seven categories of factors.[854] The Commission based its determination for each category of factors on record evidence specific to each category of factors indicating that each required category of factors is essential to identifying Long-Term Transmission Needs.[855] To the extent states may be concerned about the resulting cost allocation, we note certain clarifications below that provide greater opportunities for input to Relevant State Entities with respect to cost allocation.[856]

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[853] *E.g.*, Designated Retail Regulators Rehearing Request at 8; Undersigned States Rehearing Request at 8.

[854] *E.g.*, Order No. 1920, 187 FERC ¶ 61,068 at PP 120, 228.

[855] *Id.* P 410; *see also id.* PP 391-395, 423-424, 438, 443-445, 450-452, 459, 467, 474-477 (summarizing record evidence that indicates that the seven categories of factors are essential to identifying Long-Term Transmission Needs).

[856] *See infra* Requests for Additional Flexibility Regarding Long-Term Scenarios

302. For this reason, we also disagree with Ohio Commission Federal Advocate that the categories of factors requirements are unreasonable, arbitrary, and capricious, and will encourage a massive transmission build-out at unjust and unreasonable rates. We continue to find that the categories of factors that Order No. 1920 requires transmission providers to incorporate into the development of Long-Term Scenarios reflect the wide variety of drivers of Long-Term Transmission Needs and therefore are necessary to ensure the identification of more efficient or cost-effective transmission solutions to such needs. We also note that, in Order No. 1920, the Commission responded to concerns that certain categories of factors are too speculative or subject to change and should not be incorporated into the development of Long-Term Scenarios.[857] Further, the Commission justified the framework for treating different types of categories of factors differently in the development of Long-Term Scenarios.[858]

303. However, we set aside, in part, the requirement for transmission providers to incorporate seven specific categories of factors in the development of Long-Term Scenarios. Specifically, we set aside the requirement for transmission providers to incorporate corporate commitments[859] in Factor Category Seven when developing Long-

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Requirements section.

[857] Order No. 1920, 187 FERC ¶ 61,068 at PP 229, 231, 473.

[858] *Id.* PP 484, 507.

[859] We clarify that we distinguish in this context between "corporate commitments" and utility commitments that are made by transmission providers and load-serving entities, regardless of their corporate form.

Term Scenarios. We find that requiring transmission providers to consider corporate commitments when developing Long-Term Scenarios may introduce the risk of one class of transmission users cross-subsidizing another class of transmission users. We clarify that we continue to require transmission providers to consider corporate commitments that are likely to affect Long-Term Transmission Needs as part of Long-Term Regional Transmission Planning to the extent that these commitments affect transmission customers' transmission needs, because transmission providers must plan for the needs of all transmission customers on a comparable basis under Order Nos. 888, 890, and 1000.[860] As such, we find that it is unnecessary to require transmission providers to separately identify corporate commitments as a factor in their development of Long-Term Scenarios given that the effects of such commitments will be sufficiently incorporated into Long-Term Regional Transmission Planning through the incorporation of other Factor Categories, such as Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities).

304. We agree with Harvard ELI's argument that transmission providers must consider how the contracts and purchasing plans of all transmission customers may affect Long-Term Transmission Needs in a comparable way to how transmission providers must consider utility purchasing plans and decisions. However, we disagree with Harvard ELI

[860] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 435 ("The Commission has broad authority to remedy undue discrimination by ensuring that transmission providers plan for the needs of their customers on a comparable basis. That fundamental requirement was adopted in Order No. 888 and the reforms adopted herein should ensure that it will be implemented properly." (footnote omitted)).

that the Commission's existing open access comparability standard requires transmission providers to plan for all transmission *users* on a comparable basis. Instead, as noted above, the open access comparability standard requires planning for transmission *customers* on a comparable basis. We emphasize this distinction because, in the context of Order No. 1920, transmission "users" could refer to retail customers of load-serving entities, and those load-serving entities are either transmission providers or transmission customers of transmission providers. In focusing on transmission users, Harvard ELI's request would inappropriately expand scope of the open access comparability standard to include retail customers. Therefore, we deny Harvard ELI's requested clarification.

305. Finally, we deny Northern Virginia's request to assign transmission facility costs related to corporate commitments through the Large Generator Interconnection Procedures. The Commission did not propose such a requirement in the NOPR and, as such, this request is beyond the scope of this proceeding.

306. Aside from corporate commitments, we otherwise sustain the requirement for transmission providers in each transmission planning region to incorporate Factor Category Seven into the development of Long-Term Scenarios, while recognizing the role of states in the incorporation of this category. Specifically, transmission providers must incorporate utility commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs into the development of Long-Term Scenarios. While we require transmission providers to incorporate this category of factors into the development of Long-Term Scenarios, we emphasize that, where relevant, each of the factors within the category should be the subject of discussion

with the states who have the policy goals, and their preferences as far as how to integrate these goals should be taken into account when developing Long-Term Scenarios. We also find that utility commitments and federal, federally-recognized Tribal, state, and local policy goals could be drivers of Long-Term Transmission Needs.

307. We disagree with SERTP Sponsors and Industrial Customers that this requirement does not constitute reasoned decision making or engage with counterarguments in Order No. 1920 and note, as described above, that the requirement to incorporate Factor Category Seven into the development of Long-Term Scenarios was based on record evidence.[861] Further, the Commission acknowledged commenter concerns that utility, federally-recognized Tribal, and governmental goals may be more likely to change over the transmission planning horizon than factors in other required Factor Categories.[862] However, the Commission did not find that these commitments and goals are so speculative, amorphous, or unreliable that they should not be incorporated into Long-Term Scenarios at all.[863]

308. We also disagree with arguments that the inclusion of Factor Category Seven is unduly discriminatory or preferential.[864] The Commission requires that transmission

[861] Order No. 1920, 187 FERC ¶ 61,068 at PP 474-477 (summarizing record evidence indicating that Factor Category Seven is essential to identifying Long-Term Transmission Needs).

[862] *Id.* P 484.

[863] *Id.*

[864] SERTP Sponsors Rehearing Request at 16; Industrial Customers Rehearing

providers plan for all transmission customers' transmission needs on a comparable basis.[865] We clarify that Factor Category Seven, as modified above, is not intended to single out certain utility commitments or federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs; instead, Factor Category Seven, as modified above, captures factors that are not fully represented in the other six categories of factors and also affect Long-Term Transmission Needs. As noted in Order No. 1920, transmission providers have discretion to determine whether a proposed factor in Factor Category Seven likely affects Long-Term Transmission Needs[866] and how such factors in Factor Category Seven should be considered,[867] but we clarify such discretion must be applied in a manner that ensures comparability among transmission customers. We also clarify that "certain generation resources" in Order No. 1920's reference to "corporate, governmental, and utility commitments to rely on certain generation resources," which, as modified on rehearing, is now "governmental and utility commitments," does not refer to a certain resource type, or limit consideration of such government or utility commitments to only those commitments to rely on renewable resources.[868] Rather, this requirement means that transmission providers must consider

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Request at 54.

[865] *See, e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 435.

[866] Order No. 1920, 187 FERC ¶ 61,068 at PP 415, 417.

[867] *Id.* P 516

[868] *Id.* P 261; Industrial Customers Rehearing Request at 55.

the generation resources that a federal, state, or local government entity, federally-recognized Tribe, or utility has chosen to rely on regardless of the resource type.

309. In response to Virginia and North Carolina Commissions' request as to whether transmission providers may discount public policy factors within Factor Category Seven to zero, we reiterate that, with respect to Factor Category Seven, transmission providers have discretion as to how they account for these factors. We also clarify that transmission providers may conclude that certain factors within Factor Category Seven do not affect Long-Term Transmission Needs and, therefore, do not need to account for them when incorporating Factor Category Seven into the development of Long-Term Scenarios.[869]

310. Regarding Industrial Customers' concern that the quality of information on utility commitments make Factor Category Seven unworkable, we note the clarification below that transmission providers may rely on the open and transparent stakeholder process to identify the factors in Factor Category Seven, as modified above, in the same manner that they may rely on the open and transparent stakeholder process to identify the factors in Factor Categories One through Three.[870] We continue to believe that federal, state, and local government entities, federally-recognized Tribes, utilities, load-serving entities, and

[869] Order No. 1920, 187 FERC ¶ 61,068 at P 415.

[870] *Supra infra* Stakeholder Process and Transparency section (clarifying that transmission providers have no independent obligation to identify factors in Factor Category Seven and may rely on stakeholders to identify factors in Factor Category Seven).

their retail regulators that participate in the stakeholder process are distinctly well-positioned to provide transmission providers with vital information regarding factors in Factor Category Seven, as modified above.[871] In response to Industrial Customers' claim that the best information may be confidential,[872] we clarify that transmission providers may include what they believe to be appropriate confidentiality protections in their compliance proposals to account for proprietary commitments. The Commission will evaluate those proposals by using the established principles in Order No. 890,[873] as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 transmission planning principles.

311. We disagree with Industrial Customers' argument that the Commission's emphasis on transmission provider discretion is problematic.[874] Order No. 1920, with Factor Category Seven as modified above, strikes the right balance by allowing transmission providers discretion as to the treatment of factors within Factor Category Seven when

[871] Order No. 1920, 187 FERC ¶ 61,068 at P 530.

[872] Industrial Customers Rehearing Request at 49-50.

[873] Order No. 890, 118 FERC ¶ 61,119 at PP 471-476; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 466 (clarifying that transmission providers may include what they believe to be appropriate confidentiality protections in their proposals to account for resource retirements that might take place over the transmission planning horizon).

[874] Industrial Customers Rehearing Request at 51-53.

developing Long-Term Scenarios. In contrast to Industrial Customers' claim,[875] we do not believe that transmission providers need clear rules or standards for implementing their discretion over incorporating Factor Category Seven, as modified above, in the development of Long-Term Scenarios. We find that transmission providers can rely on their expert judgement and the information provided to them through the open and transparent stakeholder process to develop three plausible Long-Term Scenarios for purposes of identifying Long-Term Transmission Needs. Furthermore, we continue to find that concerns regarding the administrative burden of identifying specific factors are addressed by allowing transmission providers to rely on the open and transparent stakeholder process to identify factors.[876] We find that our clarification that transmission providers may rely on the open and transparent stakeholder process to identify the factors in Factor Category Seven,[877] as well as our decision to exclude corporate commitments from that Factor Category, renders moot Industrial Customers' claim that Order No. 1920 forces transmission providers to account for corporate energy commitments and goals of "all potentially known or capable-of-being known energy commitments or contracts."[878]

312. We recognize that utility commitments and federal, federally-recognized Tribal, state, and local policy goals in Factor Category Seven may initially surface as retail

[875] *Id.* at 52.

[876] Order No. 1920, 187 FERC ¶ 61,068 at P 508.

[877] *See infra* Stakeholder Process and Transparency section.

[878] Industrial Customers Rehearing Request at 53.

concerns that are addressed through arrangements with retail providers;[879] however, this fact does not obviate the need for transmission providers to account for them in the development of Long-Term Scenarios. We acknowledge that there could be an overlap between Factor Category Seven, as modified above, and other categories (e.g., integrated resource plans in Factor Category Three), because utility commitments and policy goals may be addressed through arrangements with retail providers. As discussed above,[880] transmission providers should avoid double counting the anticipated effects that those factors have on assumptions used to develop Long-Term Scenarios where the impact of factors overlaps, such that transmission providers must incorporate those factors once in the appropriate Factor Categories One through Three, not Factor Categories Four through Seven.

313. We disagree with NRECA's claim that the inclusion of Factor Category Seven expands the definition of Long-Term Transmission Needs beyond reliability, economic, or public policy issues. The Commission was clear that the drivers of transmission needs are diverse and include, but are not limited to, evolving reliability concerns, changes in

[879] SERTP Sponsors Rehearing Request at 15. In light of the discussion above, we continue to conclude that Order No. 1920—including Factor Category Seven, as modified—is within the Commission's authority notwithstanding that considerations relevant to Factor Category Seven may also arise in the context of retail transactions. *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (explaining that where the Commission regulates within its statutory authority, that regulation does not run afoul of the jurisdictional lines drawn in the FPA irrespective of any effects on areas of reserved state authority).

[880] *Supra* Requirement to Incorporate Categories of Factors section.

the resource mix, and changes in demand.[881] Foundationally, and consistent with our clarification that economic drivers contribute to Long-Term Transmission Needs,[882] we find that all seven categories of factors in Order No. 1920 pertain to Long-Term Transmission Needs because they affect the reliable and economic operation of the interconnected transmission system. The categories of factors requirements are intended to address certain deficiencies in the Commission's existing regional transmission planning requirements, including the failure to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.[883]

#### iii. Other Specific Required Categories of Factors

##### (a) Requests for Rehearing and Clarification

314. NRECA requests rehearing of the Commission's holding in Order No. 1920 that transmission providers have the discretion to determine that factors in Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities) may not affect Long-Term Transmission Needs.[884] NRECA argues that

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[881] Order No. 1920, 187 FERC ¶ 61,068 at P 299.

[882] *See supra* Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs section.

[883] Order No. 1920, 187 FERC ¶ 61,068 at P 418.

[884] NRECA Rehearing Request at 37-39 (citing Order No. 1920, 187 FERC ¶ 61,068 PP 507, 510); *see also* East Kentucky Rehearing Request at 2-3 (arguing that Order No. 1920 violates FPA section 217(b)(4) by treating state-approved integrated resource plans and expected supply obligations for load-serving entities as discretionary

Order No. 1920 is in error because the Commission took action in this regard that is at odds with the needs of load-serving entities in violation of FPA section 217(b)(4).[885] NRECA acknowledges that the Commission explained in Order No. 1920 that the final rule is consistent with FPA section 217(b)(4) and the interpretation of that statute adopted when the D.C. Circuit upheld Order No. 1000 in *South Carolina Public Service Authority v. FERC*.[886] Nonetheless, NRECA claims that Order No. 1920 is different from Order No. 1000, and therefore that decision is not dispositive—particularly as to Order No. 1920's treatment of state-approved integrated resource plans and the expected supply obligations as discretionary.[887] NRECA further argues that the Commission should revisit its conclusion that *South Carolina Public Service Authority v. FERC* remains binding precedent, because the D.C. Circuit upheld Order No. 1000's compliance with section 217(b)(4) using the deferential standard of review in *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*,[888] which was under review by the U.S.

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factors in Factor Category Three (citation omitted)); *id.* at 1 (stating that East Kentucky "specifically adopts the majority of issues identified by NRECA and incorporates the bases and arguments for rehearing set forth in the NRECA Rehearing Request for those issues").

[885] NRECA Rehearing Request at 39-40 (citing 16 U.S.C. 824q(b)(4)).

[886] *Id.* at 40-41 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 283).

[887] *Id.* at 41.

[888] *Id.* (citing *Chevron U.S.A. Inc. v. Nat. Res. Def. Council, Inc.*, 467 U.S. 837 (1984); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 54).

Supreme Court at the time NRECA submitted its request for rehearing.[889] NRECA further argues that the Commission's decision in this regard was arbitrary and capricious because Order No. 1920 was not "based on a consideration of the relevant factors" and "entirely failed to consider an important aspect of the problem."[890]

315. SERTP Sponsors request the following clarifications regarding specific categories of factors. With regard to Factor Categories One through Three, SERTP Sponsors request that the Commission expressly clarify that the open and transparent stakeholder process established by transmission providers is not intended to create an opportunity to relitigate or dispute the underlying integrated resource plans, resource projections, or laws and regulations, but instead, simply intends to create a forum in which such inputs can be brought forth to examine the potential impact on Long-Term Transmission Needs.[891] Regarding Factor Category Three, SERTP Sponsors request that the resource planning and procurement processes of non-jurisdictional transmission providers, such as those of the non-jurisdictional SERTP Sponsors, that have been approved by their respective governing authorities should be included in this Factor Category Three as scenario inputs that are to be included without discount.[892] SERTP Sponsors also request

[889] *Id.* (citing *Loper Bright Enters. v. Raimondo*, No. 22-451; *Relentless, Inc. v. Dep't of Commerce*, No. 22-1219 (U.S. argued Jan. 17, 2024)).

[890] *Id.* at 41-42 (quoting *State Farm*, 463 U.S. at 43).

[891] SERTP Sponsors Rehearing Request at 5.

[892] *Id.* at 6.

clarification that "federal, federally-recognized Tribal, state, and local laws and regulations" is intended to encompass only "enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level" as established in Order No. 1000, albeit with the addition of Tribal laws and regulations.[893] Similarly, SERTP Sponsors request clarification that for Factor Category One, such legally binding obligations, incentives (e.g., tax credits), and/or restrictions must be enacted by legislatures or promulgated by the relevant agency or Tribal authority.[894]

316. PIOs request rehearing of the Commission's findings regarding Factor Categories Four and Seven because they assert that the Commission erred when it failed to create specific guardrails to prevent transmission providers from minimizing these two categories of factors.[895] PIOs argue that the Commission must provide specific guardrails for Factor Categories Four and Seven to ensure that transmission needs are accurately assessed.[896] PIOs argue that Order No. 1920 allows "boundless discounting" of these categories, which "creates an opportunity for transmission providers to functionally ignore the Commission's mandate."[897]

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[893] *Id.* at 14-15 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 2).

[894] *Id.*

[895] PIOs Rehearing Request at 33-35.

[896] *Id.* at 33.

[897] *Id.*

317. PIOs contend that the evidence in the record does not substantiate the Commission's dismissal of the concern that the additional discretion granted to transmission providers regarding the last four categories of factors could functionally minimize these categories.[898] Regarding Factor Category Four, PIOs urge the Commission to maintain a list of best available data.[899] Regarding Factor Category Seven, PIOs request that the Commission limit the discounting of utility and corporate commitments by creating a presumption that transmission providers' discounting cannot assume greater failure to reach utility and corporate commitments than has occurred in the previous 10 years.[900]

**(b) Commission Determination**

318. We disagree with NRECA's rehearing arguments and continue to find that, while transmission providers must incorporate into the development of Long-Term Scenarios all factors in Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities) that the transmission providers determine are likely to affect Long-Term Transmission Needs, transmission providers have the discretion as to whether they must account for a specific factor in Factor Category Three in the development of Long-Term Scenarios by concluding it is likely to

[898] *Id.*

[899] *Id.* at 34.

[900] *Id.* at 35.

affect Long-Term Transmission Needs.[901] We continue to believe that the framework adopted in Order No. 1920 regarding categories of factors strikes the right balance between prescriptive requirements and flexibility.[902] Transmission providers determining whether a particular factor is likely to affect Long-Term Transmission Needs does not allow them to simply pick-and-choose one factor that they may prefer over another factor. Instead, allowing transmission providers to determine whether to account for a specific factor by concluding it is likely to affect Long-Term Transmission Needs is necessary to ensure that transmission providers develop accurate assumptions on which to base their Long-Term Scenarios.[903] Further, Order No. 1920 builds on the foundation of Order No. 890, and specifically the comparability principle, which requires that transmission providers treat similarly situated customers comparably in the transmission planning process.[904]

319. We believe that the vast majority of factors in Factor Category Three, which represent state-approved integrated resource plans and expected supply obligations for load-serving entities, will likely affect Long-Term Transmission Needs. Nevertheless,

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[901] Order No. 1920, 187 FERC ¶ 61,068 at PP 447, 510.

[902] *Id.* P 417.

[903] *Cf. id.* P 530 (discussing importance of transmission providers being able to develop more accurate assumptions to serve as the basis for their Long-Term Scenarios).

[904] *Id.* P 14 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 418-601); *see also* Order No. 890, 118 FERC ¶ 61,119 at PP 494-495 (discussing the comparability principle).

we cannot foresee every potential factor that may be identified, and we therefore find it appropriate to preserve transmission providers' discretion to conclude that a specific factor (even in Factor Category Three) will have limited or no impact on Long-Term Transmission Needs. We also emphasize, as discussed below,[905] that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to incorporate categories of factors into the development of Long-Term Scenarios in such a way that states will play an important role in ensuring that state-approved integrated resource plans are incorporated in the manner they are expected to be implemented.

320. We also disagree with NRECA's argument that the Commission acted at odds with the needs of load-serving entities in violation of FPA section 217(b)(4) by providing transmission providers with the discretion to not account for factors in Factor Category Three that a transmission provider finds are unlikely to affect Long-Term Transmission Needs. If a factor is unlikely to affect Long-Term Transmission Needs, excluding that factor in the transmission planning process is unlikely to negatively affect the needs of load-serving entities. Contrary to NRECA's claims, FPA section 217(b)(4) does not require the Commission to require transmission providers to account for factors in the development of Long-Term Scenarios that do not affect Long-Term Transmission Needs. We continue to find that Order No. 1920 satisfies the Commission's obligation under FPA section 217(b)(4) because Order No. 1920 facilitates the planning and expansion of

[905] *Infra* Stakeholder Process and Transparency section.

transmission facilities to meet load-serving entities' needs.[906] Long-Term Regional Transmission Planning, as clarified herein, is intended to enhance the transmission planning process for states, load-serving entities, and other interested parties, and, to that end, requires transmission providers to account for factors (including load-serving entities' expected supply obligations) that are likely to affect Long-Term Transmission Needs in the development of Long-Term Scenarios.

321. Further, we disagree with NRECA that the U.S. Supreme Court's decision in *Loper Bright Enterprises v. Raimondo*[907]—in which the Court overruled *Chevron U.S.A. Inc. v. Natural Resources Defense Council*, *Inc.*—requires us to reconsider the D.C. Circuit's holding in *South Carolina Public Service Authority v. FERC* as to the meaning of FPA section 217(b)(4).[908] The D.C. Circuit interpreted section 217(b)(4) and determined that this provision requires the Commission to "facilitate the planning of a reliable grid" by "seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations."[909] Order No. 1920 did not reinterpret FPA section 217(b)(4), but rather applied the interpretation adopted by the

[906] Order No. 1920, 187 FERC ¶ 61,068 PP 283, 420.

[907] 144 S.Ct. 2244 (2024).

[908] NRECA Rehearing Request at 41 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 54).

[909] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 90. Moreover, even if the D.C. Circuit had relied on *Chevron* in reaching this conclusion, the Supreme Court confirmed that "mere reliance" on *Chevron* is "not enough to justify overruling a statutory precedent." *Loper Bright*, 144 S.Ct. at 2273.

D.C. Circuit. Moreover, we believe the interpretation set forth by the Commission in Order No. 1000, endorsed by the D.C. Circuit in *South Carolina Public Service Authority v. FERC* and applied in Order No. 1920, remains the most reasonable reading of this statutory provision.[910] Fundamentally, meeting the reasonable needs of load-serving entities to satisfy their service obligations requires that sufficient transmission capacity is available to deliver power when it is needed, and fostering a reliable transmission system is the best way to ensure that such capacity is available. Order No. 1920's requirements are designed to achieve precisely that development of sufficient transmission capacity to ensure reliable and affordable delivery of needed power to meet the reasonable needs of load-serving entities, and therefore we find that it complies with FPA section 217(b)(4).

322. We grant SERTP Sponsors' request for clarification regarding the first three categories of factors and clarify that nothing in Long-Term Regional Transmission Planning is intended to relitigate or dispute the outcomes of the underlying integrated resource plans, resource projections, or laws and regulations that are (or are not) incorporated into the development of Long-Term Scenarios. The open and transparent

[910] *Compare* Order No. 1000, 136 FERC ¶ 61,051 at P 108 ("[T]his Final Rule is consistent with section 217 because it supports the development of needed transmission facilities, which ultimately benefits load-serving entities."), *with S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 90 ("Section 217 (b)(4) requires the Commission to facilitate the planning of a reliable grid, which is exactly what the Commission has done in the challenged orders."); Order No. 1920, 187 FERC ¶ 61,068 at P 283 ("As articulated in *South Carolina Public Service Authority v. FERC*, FPA section 217(b)(4) requires the Commission to 'facilitate the planning of a reliable grid,' and we do so by 'seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations.'" (alteration in original) (citation omitted)).

stakeholder process required in Order No. 1920 is a forum that provides stakeholders, including states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios.[911] For purposes of identifying Long-Term Transmission Needs, every factor is an input that transmission providers consider when determining the assumptions to use in the development of Long-Term Scenarios. Through the stakeholder process, states, transmission providers and stakeholders will have the opportunity to discuss how a factor would affect assumptions used to develop Long-Term Scenarios, if it does at all, and how the effect varies in different Long-Term Scenarios.

323. In addition, we grant SERTP Sponsors' request for clarification regarding non-jurisdictional entities,[912] in part. We clarify that, where a non-jurisdictional entity is a transmission customer of one or more transmission providers in a transmission planning region, the transmission providers must plan for the non-jurisdictional entity's needs as a transmission customer as it would for the needs of any other transmission customer, including any resource planning and procurement processes that have been approved by the respective governing authorities under Factor Category Three, for purposes of complying with the requirements of Order No. 1920. For example, each Long-Term Scenario must account for and be consistent with these factors once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission

[911] Order No. 1920, 187 FERC ¶ 61,068 at P 528.

[912] SERTP Sponsors Rehearing Request at 6.

Needs.[913] However, we further clarify that transmission providers may *not* plan for the needs of a non-jurisdictional utility transmission provider if that non-jurisdictional transmission provider has not enrolled in the transmission planning region and thereby has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities.[914] If the transmission provider were to plan for and consider non-jurisdictional transmission providers' Long-Term Transmission Needs without a way to ensure the non-jurisdictional transmission provider contributes to the costs of the resulting Long-Term Regional Transmission Facilities, the resulting cost allocation could violate the cost causation principle and result in free-ridership.[915]

324. In response to SERTP Sponsors' request for clarification regarding the meaning of "laws and regulations," we clarify that Order No. 1920 adopts the meaning of the terms used in the NOPR, namely "enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction."[916] Order No. 1920 amended the term "statutes" used in the NOPR by adding the duly enacted and

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[913] Order No. 1920, 187 FERC ¶ 61,068 at PP 507, 510.

[914] *Cf.* Order No. 1000-A, 139 FERC ¶ 61,132 at P 276 ("[T]he regional transmission planning process is *not required* to plan for the transmission needs of such a non-[jurisdictional] utility transmission provider that has not made the choice to join a transmission planning region." (emphasis added)).

[915] *El Paso Elec. Co. v. FERC*, 76 F.4th at 363-66.

[916] NOPR, 179 FERC ¶ 61,028 at P 104 n.189; *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 2. We clarify here that the definition of "laws and regulations" includes laws and regulations duly enacted by local jurisdictions, even where there are differences in how these jurisdictions enact laws or promulgate regulations.

legally binding obligations of federally-recognized Tribes.[917] We reiterate that Factor Categories One and Two include laws and regulations at the federal, federally-recognized Tribal, state, and local level.[918]

325. We disagree with PIOs' request for rehearing to create more prescriptive requirements for Factor Category Four (trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies) and Factor Category Seven (utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs).[919] We reiterate that the framework that the Commission adopted in Order No. 1920 regarding the incorporation of categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility.[920] We believe that the requirements for transmission providers to incorporate (i.e., more than merely consider) categories of factors in the development of Long-Term Scenarios, as well as to develop plausible

[917] Order No. 1920, 187 FERC ¶ 61,068 at P 434.

[918] *Id.* P 409. It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[919] PIOs Rehearing Request at 33.

[920] Order No. 1920, 187 FERC ¶ 61,068 at P 417.

Long-Term Scenarios with the best available data,[921] are adequate to safeguard against "boundless discounting" and opportunities to "functionally ignore the Commission's mandate."[922]

326. More specifically, we disagree with PIOs' request to require on rehearing that transmission providers incorporate certain factors from a Commission-maintained list of data sources for Factor Category Four. As an initial matter, we find that it is unnecessary to grant PIOs' request because transmission providers' technical expertise and the required open and transparent stakeholder process to identify factors are sufficient to ensure that transmission providers implement the requirements of Long-Term Regional Transmission Planning. In addition to the Commission's concerns regarding regional variation and stifled innovation identified in Order No. 1920,[923] we conclude that there are practical challenges associated with the Commission establishing and maintaining a list of data sources. For example, transmission providers already collect data similar to the data needed for these factors for other applications, and the Commission would be duplicating this data collection effort. We believe that transmission providers working with Relevant State Entities and other stakeholders in their regions are better equipped to

[921] *Id.* PP 413-414.

[922] PIOs Rehearing Request at 33.

[923] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 639 (declining to impose further requirements as to data uniformity because regional variation may make uniformity challenging and because it could stifle innovation that may improve Long-Term Regional Transmission Planning).

understand the unique circumstances of their regions and to compile data and inputs for the required categories of factors.

327. With respect to Factor Category Seven, we decline to limit the discounting of utility and corporate commitments as proposed by PIOs.[924] In this case, we find that transmission providers may face practical challenges in accurately quantifying the historical rate of failure for utility commitments; moreover, the historical rate of failure is not necessarily determinative of future achievement rates for such commitments. In addition, limiting how transmission providers manage the uncertainty associated with utility commitments may have unintended consequences. For example, such a limit would not allow transmission providers to adapt their treatment of utility commitments in response to, for example, industry-wide changes that make it more challenging for utilities to meet prior commitments. We believe that the existing requirements in Order No. 1920[925] are adequate to safeguard against boundless discounting of factors in Factor Category Seven.[926]

[924] The issue of discounting corporate commitments is rendered moot by our decision to set aside the requirement to include these commitments in Factor Category Seven above.

[925] *Id.* PP 413-414.

[926] PIOs Rehearing Request at 33.

### iv. Requests for Additional Requirements

#### (a) Requests for Rehearing

328. Invenergy requests rehearing, asserting that the Commission erred by not requiring transmission providers to include "advanced-stage" merchant high-voltage direct current (HVDC) transmission facilities in the list of factors to be considered when developing Long-Term Scenarios.[927] Invenergy claims this omission is unduly discriminatory against advanced-stage merchant HVDC transmission.[928] Invenergy also asserts that the Commission failed to consider significant evidence in Order No. 1920 because the Commission failed to address AEE's comments, which argued that merchant HVDC transmission facilities must be included in at least one Long-Term Scenario in order to address potential undue discrimination against merchant HVDC transmission facilities. According to Invenergy, AEE asserted that it is important to include merchant HVDC transmission facilities in at least one Long-Term Scenario because merchant HVDC transmission facilities are developed by nonincumbent transmission developers and this inclusion guards against potential undue discrimination.[929] In addition, Invenergy claims that failure to utilize critical and readily available information will result in Long-Term Scenarios that do not accurately reflect the topography of the system, and that this information should be included to guard against potential undue discrimination from

[927] Invenergy Rehearing Request at 2, 6-7.

[928] *Id.* at 10.

[929] Invenergy Rehearing Request at 9 (citing AEE NOPR Reply Comments at 19).

incumbent transmission owners.[930] Invenergy argues that the Commission ignored significant evidence in the record from Invenergy and others on this issue.[931]

**(b) Commission Determination**

329. In response to Invenergy's request for rehearing, we reiterate that the Commission did not propose specific requirements in the NOPR regarding merchant HVDC transmission facilities under development and was not persuaded by the evidence in the record that it should include advanced-stage HVDC transmission facilities in the minimum set of known determinants of Long-Term Transmission Needs.[932] Invenergy has not clearly articulated how merchant HVDC transmission facilities are essential to identifying, or are known and identifiable drivers of, Long-Term Transmission Needs.

330. In the NOPR, the Commission referenced merchant transmission facilities only once,[933] and that reference was in the context of a larger proposed requirement that the Commission declined to adopt in Order No. 1920.[934] Order No. 1920 addressed specific

[930] *Id.* at 8-9.

[931] *Id.* at 9.

[932] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 493.

[933] NOPR, 179 FERC ¶ 61,028 at P 150 (In the context of the NOPR proposal for the identification of geographic zones, the Commission proposed to include "any merchant or other entity commitments to build . . . transmission facilities" as one of seven mandatory considerations to assess generation developers' commercial interest in developing generation within each designated geographic zone.).

[934] Order No. 1920, 187 FERC ¶ 61,068 at P 665 (stating that "the [identification of geographic zones] NOPR proposal is not warranted at this time").

deficiencies with the Commission's existing regional transmission planning and cost allocation requirements but did not identify issues surrounding merchant transmission as one of those deficiencies.[935]

331. We disagree with Invenergy's claim that the exclusion of proposed but not yet built merchant HVDC transmission facilities from the required factors underlying the Long-Term Scenarios is unjust and unreasonable.[936] In Order No. 1920, the Commission described the seven specific categories of factors required by the Commission as "essential to identifying Long-Term Transmission Needs" and "known and identifiable drivers of Long-Term Transmission Needs."[937] Although Invenergy claimed that one of its merchant HVDC transmission facilities could *address* transmission needs,[938] Invenergy has failed to clearly articulate how proposed but not yet built merchant HVDC

[935] *Id.* P 139 ("[W]e find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that reforms to those requirements are thus necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.").

[936] Invenergy Rehearing Request at 8.

[937] Order No. 1920, 187 FERC ¶ 61,068 at P 410.

[938] Invenergy Initial NOPR Comments at 7 ("A planned 5,000 MW HVDC line such as Grain Belt's would be a significant system addition, and could itself provide system benefits or even address transmission needs otherwise identified through the planning process . . . .").

transmission facilities are essential to identifying, or are known and identifiable drivers of, Long-Term Transmission Needs. However, as indicated in Order No. 1920, transmission providers may be aware of additional categories of factors beyond those adopted in the final rule that drive Long-Term Transmission Needs and may incorporate additional categories of factors into the development of Long-Term Scenarios.[939] We clarify that, if transmission providers elect to use additional categories of factors beyond the required categories of factors in Order No. 1920 in the development of Long-Term Scenarios, the transparency requirements set forth in Order No. 1920 also apply to the additional categories of factors.[940] Pursuant to this clarification, transmission providers must publish on the public portion of an OASIS or other public website: (1) the list of each additional categories of factors, and the factors in each of the additional categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each additional category of factors and a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each additional category of factors and each of the additional factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in each additional category of factors; and (5) a list of the factors that they considered but did not incorporate in each additional category of factors in their Long-Term Scenarios. Consistent with Order No. 1920, we find that this transparency is

[939] Order No. 1920, 187 FERC ¶ 61,068 at P 493.

[940] *See id.* PP 528-533.

necessary to make clear to stakeholders which specific additional categories of factors and factors transmission providers incorporate into Long-Term Scenarios and how they are incorporated. We believe this posting requirement for additional categories of factors will also provide greater transparency into how transmission providers develop Long-Term Scenarios, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors.[941] Accordingly, in transmission planning regions where proposed HVDC transmission facilities may play a role in shaping Long-Term Transmission Needs, transmission providers have the flexibility to consider and incorporate such facilities into their Long-Term Scenarios.

332. We also disagree with Invenergy's argument that the Commission has failed to direct transmission providers to use critical—and readily available—information related to the future electric power system, which renders the resulting Long-Term Scenarios unjust and unreasonable.[942] Order No. 1920 requires transmission providers to develop Long-Term Scenarios with data inputs that are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000.[943] In addition, in Order No. 1920, the Commission found that transmission providers must use best available data when determining whether each factor is likely to affect Long-Term Transmission Needs.

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[941] *Id.* P 534.

[942] Invenergy Rehearing Request at 9.

[943] Order No. 1920, 187 FERC ¶ 61,068 at P 633.

Once transmission providers have determined that a factor is likely to affect Long-Term Transmission Needs, they must use the best available data when they then account for that factor in the development of Long-Term Scenarios.[944]

333. We also disagree with Invenergy's claim that the Commission ignored significant evidence in the record.[945] We remain unpersuaded by the evidence in the record that the Commission should include advanced-stage HVDC transmission facilities in the minimum set of known determinants of Long-Term Transmission Needs.[946] Invenergy's experience with its Grain Belt project in the MISO Long Range Transmission Plan speaks to a separate issue currently before the Commission.[947]

334. Finally, we disagree with Invenergy's argument that the Commission's inclusion of a wide range of factors, including generation interconnections, but exclusion of advanced-stage merchant HVDC facilities is unduly discriminatory and opens such developers to further potential undue discrimination.[948] The Commission found it appropriate to require transmission providers to incorporate Factor Category Six

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[944] *Id.*

[945] Invenergy Rehearing Request at 9 ("As demonstrated above, multiple commenters, including Invenergy, the Clean Energy Associations, and others placed evidence into the record explaining why merchant HVDC transmission facilities must be included.").

[946] Order No. 1920, 187 FERC ¶ 61,068 at P 493.

[947] *Invenergy Transmission LLC v. Midcontinent Indep. Sys. Operator, Inc.*, Complaint, Docket No. EL22-83-000 (filed Aug. 8, 2022).

[948] Invenergy Rehearing Request at 10.

(generator interconnection requests and withdrawals) into the development of Long-Term Scenarios because generation interconnection queues provide important information about future generation development over the transmission planning horizon and therefore affect Long-Term Transmission Needs.[949] We cannot make a similar finding for advanced-stage merchant HVDC transmission based on the record in this proceeding, nor do we conclude (and Invenergy has not demonstrated) that the exclusion of advanced-stage merchant HVDC facilities from the required categories of factors opens merchant transmission developers to potential undue discrimination. We also are not persuaded by Invenergy's reference to AEE's comments claiming that being a nonincumbent transmission developer rises to the level of potential undue discrimination that must be remedied by requiring merchant HVDC to be included in Long-Term Scenarios. To the extent that similar potential undue discrimination claims for nonincumbent merchant HVDC transmission developers are pending in other proceedings, the Commission will address those claims based on the evidence in those proceedings. We note that AEE provides no evidence of potential undue discrimination and that AEE itself has not filed a rehearing request on this issue. Finally, we clarify that transmission providers, in addressing interconnection requests and withdrawals under Factor Category Six, must include merchant transmission developer interconnection requests in the development of Long-Term Scenarios, and in a manner comparable to other interconnection requests.

[949] Order No. 1920, 187 FERC ¶ 61,068 at P 472.

### c. Stakeholder Process and Transparency

#### i. Order No. 1920 Requirements

335. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios. The Commission further required transmission providers to publish on the public portion of an OASIS or other public website the following information: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of those factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.[950] In addition, the Commission required transmission providers to post this information after stakeholders, including states, have had the meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of

[950] *Id.* P 528.

Long-Term Scenarios.[951] The Commission explained that this requirement will provide greater transparency into how transmission providers develop Long-Term Scenarios, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors,[952] and the Commission explained that this transparency also ensures that transmission providers review stakeholder-proposed factors in a fair and non-discriminatory manner.[953]

336. The Commission also required transmission providers, consistent with Order No. 890's transparency transmission planning principle, to make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario.[954] Given the importance of a robust stakeholder process to developing more accurate assumptions to serve as the basis for Long-Term Scenarios, Order No. 1920 required transmission providers to give stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate into the development of Long-Term Scenarios, including how to account for a specific factor in terms of how the factor may affect Long-Term Transmission Needs. The Commission explained that this meaningful opportunity includes the opportunity to propose factors, provide information and identify sources of best available data, propose how a factor may affect Long-Term

[951] *Id.* P 533.

[952] *Id.* P 534.

[953] *Id.* P 535.

[954] *Id.* P 305 (citing Order No. 890, 118 FERC ¶ 61,119 at P 471).

Transmission Needs, and explain how that factor could be reflected in the development of Long-Term Scenarios, including the extent to which it is appropriate to discount the effects of certain factors on Long-Term Transmission Needs.[955]

337. The Commission further found in Order No. 1920 that stakeholder input is particularly important for factors in the first three categories of factors, because federal, state, and local government entities, federally-recognized Tribes, and utilities, load-serving entities, and their retail regulators that participate in the stakeholder process are distinctly well-positioned to provide transmission providers with vital information on how the factors over which they have authority or that they govern are likely to influence Long-Term Transmission Needs over the transmission planning horizon.[956] The Commission recognized that different stakeholders may provide information about the same factor that is contradictory and allowed transmission providers to weigh more heavily one source of information over another.[957]

**ii. Requests for Rehearing and Clarification**

338. NESCOE requests clarification that transmission providers must rely on states in developing Long-Term Scenarios where state laws, regulations, and/or policies are driving Long-Term Transmission Needs. If the Commission does not provide this

[955] *Id.* PP 529-530.

[956] *Id.* P 530.

[957] *Id.* P 531.

clarification, NESCOE requests rehearing.[958] NESCOE explains that state officials have expertise in connection with these matters such that transmission providers should rely on states for input regarding the details of state requirements in Factor Categories One, Two, and Seven. NESCOE claims that, in the absence of this clarification, transmission providers may devote resources to developing Long-Term Scenarios that are less useful to transmission planning regions.[959] Similarly, PJM States request clarification of the degree to which transmission providers should defer to, weigh, or consider the input of states as it relates specifically to state laws and integrated resource plans. PJM States argue that states have a unique role as to these subjects, and that transmission providers should not treat state perspectives the same as those of any other stakeholder.[960]

339. PIOs request rehearing such that the Commission would strengthen the transparency provisions by requiring transmission providers to provide more detailed explanations of the factors to be used and to justify any discounting of factors in Factor Categories Four through Seven. PIOs argue that stronger transparency provisions would foster more meaningful stakeholder processes.[961] Specifically, PIOs contend that, with respect to the information that transmission providers must publish on the public portion of an OASIS or other public website, the Commission should replace the third item, i.e.,

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[958] NESCOE Rehearing Request at 11.

[959] *Id.* at 20-21.

[960] PJM States Rehearing Request at 4.

[961] PIOs Rehearing Request at 36.

"a general statement explaining how [transmission providers] will account for each of [the factors that they will account for in their Long-Term Scenarios]," with "a detailed description of the reasoning and methodology used to account for each factor, as well as providing the actual data inputs when possible."[962]

340. PIOs criticize the Commission's rationale for declining to include this requirement, i.e., that the burden would not be justified by the benefit of such additional information. PIOs argue that requiring transmission providers to justify their discounting decisions would help hold transmission providers accountable, incentivize more accurate discounting assumptions, and guard against pressure from self-interested stakeholders to excessively discount factors.[963] PIOs contend that Order No. 1920 is arbitrary and capricious because failing to require more detailed explanations of the factors to be used or to justify any discounting of factors in Factor Categories Four through Seven does not flow rationally from Order No. 1920's "more fundamental findings" as to the requirements for transmission providers to provide meaningful opportunity for stakeholder input and to make the development of Long-Term Scenarios transparent.[964]

341. SERTP Sponsors request that the Commission clarify that transmission providers have the discretion to include or to exclude an assumption from the development of a Long-Term Scenario where stakeholders do not provide transmission providers with

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[962] *Id.*

[963] *Id.* at 37-38.

[964] *Id.* at 38 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 305).

sufficient information as to whether a potential assumption or factor is likely to affect Long-Term Transmission Needs. SERTP Sponsors provide the example of a generator whose point of interconnection is unknown and contend that transmission providers should not be obligated to hypothesize arbitrarily as to that point of interconnection, because doing so likely would yield implausible Long-Term Scenarios and would not result in cost-effective or efficient transmission planning.[965]

342. SERTP Sponsors request that the Commission clarify that transmission providers may rely on stakeholders to identify factors in Factor Categories Four through Seven, and, if stakeholders identify no such factors, that transmission providers may but need not do so. SERTP Sponsors contend that Order No. 1920 implies but does not clearly provide for this requested clarification.[966] SERTP Sponsors also request that the Commission clarify that transmission providers may rely upon stakeholders to identify factors that, unlike factors in Factor Categories One through Three, do not pertain directly to a specific transmission provider in the relevant transmission planning region.[967] If the Commission does not so clarify, SERTP Sponsors request rehearing on the grounds that requiring transmission providers to identify such factors would be unduly burdensome.[968]

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[965] SERTP Sponsors Rehearing Request at 13-14.

[966] *Id.* at 13 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 516).

[967] *Id.* at 14 & n.33.

[968] *Id.* at 14.

343. Finally, SERTP Sponsors request that the Commission clarify the required timing of when transmission providers must publish on the public portion of an OASIS or other public website the information about factors required by Order No. 1920. SERTP Sponsors contend that Order No. 1920 does not make clear whether this information must be published in conjunction with transmission providers' compliance filings or by the start of the first Long-Term Regional Transmission Planning cycle. SERTP Sponsors argue that the Commission should require transmission providers to post this information after the conclusion of the period during which stakeholders provide input into these matters.[969]

### iii. Commission Determination

344. In response to NESCOE's and PJM States' requested clarification that transmission providers must rely on states in developing Long-Term Scenarios where state laws, regulations, and/or policies are driving Long-Term Transmission Needs, we grant the following clarifications. We clarify that states must have a meaningful opportunity to provide timely input on the development of Long-Term Scenarios, including factors and data inputs, and to explain how their own policies and planning affect Long-Term Transmission Needs.[970] Furthermore, we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to

[969] *Id.* at 26.

[970] Order No. 1920, 187 FERC ¶ 61,068 at PP 528-537, 560-562, 634.

account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios.[971] Specifically, transmission providers shall consult with Relevant State Entities and any other authorized entities as to whether a specific state policy must be accounted for as a factor within each category (i.e., if the specific state policy will likely affect Long-Term Transmission Needs), how to account for the specific state policy in the development of Long-Term Scenarios (e.g., the method and data used to forecast generation resources added because of a specific state policy), and how to adjust the treatment of the specific state policy across Long-Term Scenarios (e.g., assume certain policy-related outcomes materialize in some but not all Long-Term Scenarios).[972]

345. We further clarify that, where transmission providers determine that a factor based on a state's law, regulation, or policy is likely to affect Long-Term Transmission Needs, transmission providers should rely on the state in determining *how* to account for such a state-related factor when developing Long-Term Scenarios. For example, for a state that has required integrated resource planning processes, transmission providers should include one of the state's preferred power system trajectories, including both the supply

[971] A Relevant State Entity may believe that a different state entity would be better situated to advise transmission providers as to how state policy may affect Long-Term Transmission Needs. For example, the state entity responsible for electric utility regulation may believe that the state entity responsible for energy policy is in a better position to advise on state energy policy implementation. In this case, the Relevant State Entity may authorize the other state entity as its representative in discussions with transmission providers.

[972] *See id.* P 417.

and demand side resource trajectory as appropriate, in each of Long-Term Scenarios, or include different state-preferred power system trajectories in different Long-Term Scenarios. As such, transmission providers could include in the development of Long-Term Scenarios the set of resource capacity additions and/or retirements expected by a state based on the incentives or requirements in that state's law. If transmission providers determine, based on input provided by the state or their own judgment, that a factor based on a state's law, regulation, or policy is likely to affect Long-Term Transmission Needs, transmission providers should then determine whether and how to account for that factor in the development of Long-Term Scenarios.

346. We disagree with PIOs that a more detailed explanation of the factors that transmission providers will account for in their Long-Term Scenarios and justification of the factors that they will discount is warranted. Broadly, we affirm that Order No. 1920 strikes the right balance between prescriptive requirements and flexibility with respect to the development of Long-Term Scenarios.[973] We also find that this is true with respect specifically to Order No. 1920's requirements on stakeholder process and transparency. PIOs request that we require "a detailed description of the reasoning and methodology used to account for each factor, as well as providing the actual data inputs when possible" and that we require transmission providers to justify their discounting decisions of factors in Factor Categories Four through Seven. We find that such requirements are not necessary to ensure that stakeholders have a meaningful opportunity to provide input.

[973] *Id.*

We further find that the requirements of Order No. 1920 ensure that the development of Long-Term Scenarios is sufficiently transparent,[974] and that PIOs' requested requirements are not needed to ensure that transmission providers use accurate data.[975]

347. We emphasize that Order No. 1920 sets minimum requirements with which all transmission providers must comply, and we are not convinced that the level of information that PIOs seek is necessary. Further, we clarify that nothing in Order No. 1920 prevents transmission providers from providing more than the minimum amount of information that we require, including the level of detail requested by PIOs. Moreover, we conclude that granting PIOs' request is unnecessary because the existing transparency requirements in Order No. 1920[976] are sufficient to ensure that "the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario" are transparent.[977]

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[974] *See id.* P 533 (requiring transmission providers to publicly post "(1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of these factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.").

[975] PIOs Rehearing Request at 36-37. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 636 ("We find that a requirement to use the best available data inputs is warranted to ensure that transmission providers are regularly updating data inputs and using timely and accurate data inputs to inform Long-Term Scenarios.").

[976] *Supra* P 346 n.975.

[977] Order No. 1920, 187 FERC ¶ 61,068 at P 305.

348. We decline to provide clarification to SERTP Sponsors with respect to the inclusion or exclusion of factors for which stakeholders provide insufficient information, and we similarly decline to address SERTP Sponsors' hypothetical in the abstract.[978] Generally, transmission providers can rely on stakeholders for input on the development of Long-Term Scenarios, including factors and data inputs, and must consult with and consider the positions of Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative regarding how their policies and planning affect Long-Term Transmission Needs and the assumptions that will be used in the development of Long-Term Scenarios. Transmission providers implementing Long-Term Regional Transmission Planning necessarily will balance competing interests from within the transmission planning region when developing Long-Term Scenarios, and Order No. 1920 provides transmission providers with sufficient flexibility to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements.[979]

349. In response to SERTP Sponsors' request for clarification regarding the identification of factors in Factor Categories Four through Seven, we clarify that transmission providers must identify factors in Factor Categories Four, Five, and Six but

[978] It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[979] Order No. 1920, 187 FERC ¶ 61,068 at P 1027.

need not independently identify factors in Factor Category Seven – rather, transmission providers may rely on stakeholders, including states, to bring such factors to their attention. We believe that factors in Factor Categories One, Two, Three, and Seven arise from stakeholder decision-making and legal processes that generally are external to the transmission provider and are therefore suitable for identification by the states and other stakeholders that govern or have authority over those processes. Therefore, as with factors in Factor Categories One, Two, and Three, transmission providers may rely on stakeholders to identify factors in Factor Category Seven in the development of Long-Term Scenarios, particularly through the open and transparent stakeholder process required by Order No. 1920.[980] In contrast, we believe that factors in Factor Categories Four, Five, and Six relate to the expertise of transmission providers arising from their day-to-day operations. For example, transmission providers manage processes for processing interconnection requests and withdrawals (Factor Category Six) and determining the impact of resource retirements (Factor Category Five). In managing those processes and the day-to-day operations of the transmission system, transmission providers also gain information about trends in technology and fuel costs within and outside the electricity supply industry (Factor Category Four). Therefore, we clarify that transmission providers have an independent obligation to identify factors in Factor

[980] *Id.* P 508. We note, however, an exception to this general rule. Where the transmission provider is the entity that has made a commitment that affects Long-Term Transmission Needs, the transmission provider may not rely on the identification by stakeholders of this factor or these factors.

Categories Four, Five, and Six regardless of whether any such factors are identified by stakeholders and must, where relevant, consult with and consider the positions of Relevant State Entities and any entities authorized by the Relevant State Entities. In response to SERTP Sponsors' argument that, if transmission providers must independently identify factors in Factor Categories Four through Seven, the Commission would be holding transmission providers to a burdensome unattainable standard, we clarify that the independent obligation to identify factors in Factor Categories Four through Six does not require transmission providers to identify every potentially knowable factor within those categories. Transmission providers can use their prior experience and professional judgement to independently identify factors in Factor Categories Four, Five, and Six.

350. Finally, in response to SERTP Sponsors' request for clarification regarding the timing of transmission providers' publication of information regarding the factors to be incorporated into the development of Long-Term Scenarios on the public portion of an OASIS or other public website, we clarify that transmission providers do not need to include this information with the filings that they submit to comply with Order No. 1920. Rather, we clarify that Order No. 1920 requires transmission providers to post this information as part of each Long-Term Regional Transmission Planning cycle after stakeholders, including states, have had a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of

Long-Term Scenarios for that planning cycle.[981] We further clarify that publication of information regarding the factors to be incorporated into the development of Long-Term Scenarios must occur before transmission providers finish developing Long-Term Scenarios,[982] and, in any event, well before the transmission provider has identified Long-Term Transmission Needs.

#### 5. Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements

351. This section responds to requests for rehearing or clarification to permit additional flexibility with respect to multiple interrelated Long-Term Scenario requirements, including transmission providers' incorporation of factors from seven categories of factors; the treatment of factors in the first three categories of factors; and the number, type, and plausibility of Long-Term Scenarios.

##### a. Order No. 1920 Requirements

352. In Order No. 1920, the Commission required transmission providers in each transmission planning region to develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section.[983] The Commission adopted the NOPR proposals to require transmission

[981] *Id.* P 533.

[982] *See id.* P 534 (discussing the value of posting requirement in terms of the transparency into how transmission providers develop Long-Term Scenarios).

[983] *Id.* P 559.

providers in each transmission planning region to publicly disclose information and data inputs used to create each Long-Term Scenario and provide stakeholders an opportunity to provide timely and meaningful input into how Long-Term Scenarios are developed.[984]

353. The Commission required transmission providers in each transmission planning region to develop a plausible and diverse set of at least three Long-Term Scenarios.[985] The Commission also required that each individual Long-Term Scenario be plausible to avoid resting on assumptions about factors and data inputs that do not reasonably capture possible future outcomes. The Commission clarified that the term "diverse" means that the *set* of Long-Term Scenarios must represent a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.[986]

354. The Commission also required transmission providers in each transmission planning region to develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[987] In Order No. 1920, the Commission provided transmission providers with flexibility to conduct

[984] *Id.* P 560.

[985] *Id.* PP 575-577.

[986] *Id.* P 576.

[987] *Id.* P 593.

this sensitivity either before or after identifying potential regional transmission solutions to the Long-Term Transmission Needs identified using those Long-Term Scenarios.[988] Order No. 1920 did not preclude transmission providers from considering additional sensitivities, and the Commission encouraged transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.[989] The Commission found that modeling extreme weather events as sensitivities is appropriate for Long-Term Regional Transmission Planning.[990]

**b. Requests for Rehearing and Clarification**

355. PJM requests rehearing such that the Commission either would consider requests for flexibility or permit flexibility that PJM contends would be required for PJM to develop Long-Term Scenarios and sensitivities consistent with a draft long-term transmission planning process that PJM has developed.[991] PJM argues that Order

[988] *Id.* P 594.

[989] *Id.* P 597.

[990] *Id.* P 598.

[991] *See* PJM Rehearing Request at 12 ("Granting rehearing and permitting flexibility with respect to the issues identified below would allow PJM to use the PJM Long Term Regional Transmission Planning process as the foundation for a long-term planning process that achieves the objectives of the Final Rule, even though implementation details may differ in some way from those the Final Rule prescribes." (footnote omitted)); *id.* at 14 ("PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to accommodate regional differences."); *id.* at 19 ("[G]iven the diversity among regions, PJM believes it is appropriate to allow transmission planners to work with states and stakeholders within their respective regions to determine the appropriate number of and specific scenarios to be used in the Long-Term Regional Transmission Planning process, as well as giving the transmission provider flexibility to determine how to weigh specific factors used to develop the

No. 1920's requirements with respect to the development of Long-Term Scenarios are overly prescriptive, particularly with respect to the requirements that transmission providers develop three Long-Term Scenarios that each incorporate seven categories of factors and that transmission providers cannot discount factors in Factor Categories One through Three.[992] PJM contends that these requirements would "complicate" PJM's efforts to promote more efficient or cost-effective regional transmission planning and development.[993]

356. PJM explains that, under the draft long-term transmission planning process that PJM developed, PJM would develop three distinct scenarios that would "generally account for the seven factors" required by Order No. 1920: the "Base Reliability Scenario," the "Medium Public Policy Scenario," and the "High Public Policy Scenario."[994] The Base Reliability Scenario would include certain "categories of factors," including: the PJM Load Forecast Report; announced retirements and retirements required by Public Policy Requirements; in-service generation and generation that is not yet in service but with an executed service agreement or State Agreement

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assumptions upon which Long-Term Scenarios are based."); *id.* ("PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to develop Long-Term Scenarios and conduct sensitivity analyses in such a way as to accommodate regional differences.").

[992] *Id.* at 13 n.59, 16, 18.

[993] *Id.* at 16, 18.

[994] *Id.* at 16-18.

Approach reservation; and replacement generation taken mainly from the PJM Service Request process.[995] The Medium Public Policy Scenario would build on the Base Reliability Scenario by including certain additional Public Policy Requirements that otherwise would be brought to PJM as part of the State Agreement Approach process, such as state renewable portfolio standards.[996] The High Public Policy Scenario would in turn build on the Medium Public Policy Scenario by modeling "Public Policy Objectives," defined as Public Policy Requirements that are not yet in a statute or regulation.[997] PJM argues that this draft process would demonstrate a wide range of possible transmission needs, and would be a prudent way to account for long-term needs without overbuilding the transmission system.[998]

357. PJM States and West Virginia Commission request that the Commission clarify that—or, in the alternative, request rehearing such that—Order No. 1920 does not prohibit the development by transmission providers of a fourth Long-Term Scenario or additional sensitivities that are designed to provide information to states on the factors driving the need for transmission facilities and on their costs and benefits. PJM States and West Virginia Commission explain that Order No. 1920 requires that transmission providers assume that all legally binding obligations are followed, state-approved

[995] *Id.* at 16-17.

[996] *Id.* at 17-18.

[997] *Id.* at 18 & n.80.

[998] *Id.* at 19.

integrated resource plans are followed, and expected supply obligations for load-serving entities are met and not discounted. PJM States and West Virginia therefore express concern that Order No. 1920 places "undue restrictions" on the development of scenarios or sensitivities that can provide the information sought by states, which PJM States contend would be necessary to assist in cost allocation determinations and in siting and safety decisions.[999]

358. Ohio Commission Federal Advocate argues that Order No. 1920 makes it impossible to identify and evaluate transmission facilities that are required due to other states' laws, as well as to "isolate the incremental costs" arising from those laws. Ohio Commission Federal Advocate states that this lack of transparency is not in the public interest, and that the Commission should clarify that counterfactual scenarios that do not reflect compliance with state law are permissible because they provide important insights into the factors driving transmission needs.[1000]

359. Virginia and North Carolina Commissions argue that the Commission should grant rehearing such that Order No. 1920 would require or allow for one or more "baseline" planning scenarios that exclude all or some policy-driven factors. Virginia and North Carolina Commissions explain that Order No. 1920 requires transmission providers to incorporate seven categories of factors in each Long-Term Scenario, and that the

[999] PJM States Rehearing Request at 4-6; West Virginia Commission Rehearing Request at 14-16.

[1000] Ohio Commission Federal Advocate Rehearing Request at 18.

Commission did not allow flexibility for additional scenarios that exclude some or all of these factors. Virginia and North Carolina Commissions contend that, without a "baseline" scenario, Relevant State Entities and other stakeholders will not have adequate transparency regarding the critical drivers of transmission needs or the costs associated with a particular transmission facility, nor will they be able to evaluate whether cost allocation methods comply with the Commission's cost causation principles.[1001]

360. Finally, in PJM's general request for additional flexibility in the development of Long-Term Scenarios, PJM identified the requirement in Order No. 1920 to conduct a specific sensitivity for each Long-Term Scenario as an example of a requirement that it believes to be overly burdensome.[1002] PJM States and West Virginia Commission request that the Commission clarify that—or grant rehearing such that—transmission providers are required, or even permitted, to provide additional sensitivity analyses to the states that best inform them on required transmission facility needs, costs, and benefits based on variations or exclusions of specific factors or categories of factors, including those in the first three categories of factors.[1003]

[1001] Virginia and North Carolina Commissions Rehearing Request at 4-5.

[1002] PJM Rehearing Request at 16.

[1003] PJM States Rehearing Request at 4-5; West Virginia Commission Rehearing Request at 14-16.

### c. Commission Determination

361. We disagree with PJM's rehearing arguments and deny its requested clarification with respect to flexibility regarding the development of Long-Term Scenarios. Specifically, we continue to find that transmission providers must develop at least three distinct Long-Term Scenarios as defined in Order No. 1920, and that transmission providers must incorporate the seven categories of factors set forth in Order No. 1920 into each of those Long-Term Scenarios,[1004] as also clarified above.[1005] As the Commission held in Order No. 1920, and as we continue to find here, the Commission's regional transmission planning requirements currently fail to adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs, and the incorporation of the seven categories of factors is necessary because these categories of factors are essential to identifying Long-Term Transmission Needs.[1006] Failing to require that transmission providers incorporate these categories of factors into the development of each Long-Term Scenario would increase the likelihood that transmission providers will continue to underestimate—or omit entirely—certain known

[1004] Order No. 1920, 187 FERC ¶ 61,068 at PP 409, 559.

[1005] *See supra* Long-Term Scenarios Requirements, Stakeholder Process and Transparency section.

[1006] Order No. 1920, 187 FERC ¶ 61,068 at P 410.

determinants of Long-Term Transmission Needs in their regional transmission planning processes.[1007]

362. We also continue to find that transmission providers must assume that legally binding obligations (i.e., federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met.[1008] Each Long-Term Scenario must account for and be consistent with factors in these first three categories of factors, because these categories of factors are part of the primary drivers of Long-Term Transmission Needs.[1009]

363. We disagree with PJM's apparent contention that complying with Order No. 1920 requirements with respect to Long-Term Scenarios will "complicate" PJM's efforts to conduct Long-Term Regional Transmission Planning[1010] as it is set forth in Order No. 1920.[1011] Instead, we reiterate that Order No. 1920's Long-Term Scenarios

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[1007] *Id.* P 411.

[1008] We continue to find that it is appropriate for transmission providers to assume that legally binding obligations are met, unless and until there is a change in law. *Id.* P 512.

[1009] *Id.* PP 507, 512.

[1010] PJM Rehearing Request at 18-19.

[1011] To the extent that PJM was requesting that the Commission address in this order PJM's proposed long-term transmission planning process, we decline to address such a request here because doing so would be premature and more properly the subject of compliance.

requirements strike a reasonable balance between, on the one hand, ensuring that transmission providers identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities that would meet those needs, and, on the other hand, providing sufficient flexibility for transmission providers to develop and use Long-Term Scenarios in a way that reflects the unique characteristics of their respective transmission planning regions.[1012] We continue to find that Order No. 1920's categories of factors requirements strike the right balance between prescriptive requirements and flexibility[1013] and that they are sufficiently detailed to address the need for reform without limiting regional flexibility.[1014] Further, we continue to find that the requirement to develop at least three distinct Long-Term Scenarios that meet Order No. 1920's requirements strikes the appropriate balance between establishing a sufficient number of Long-Term Scenarios and the associated burden of developing and using Long-Term Scenarios in Long-Term Regional Transmission Planning.[1015]

364. In response to the requests for clarification and/or rehearing of various Order No. 1920 requirements related to Long-Term Scenarios and sensitivities submitted by PJM States, Virginia and North Carolina Commissions, Ohio Commission Federal Advocate, and West Virginia Commission, we clarify that Order No. 1920 allows

[1012] Order No. 1920, 187 FERC ¶ 61,068 at P 298.

[1013] *Id.* P 417.

[1014] *Id.* P 421.

[1015] *Id.* P 559.

transmission providers to conduct analyses in addition to those required by Order No. 1920—including additional scenarios or sensitivities[1016]—at the transmission providers' discretion or at the request of the transmission planning region's Relevant State Entities and/or other stakeholders.

365. Specifically, we clarify that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es). We believe that additional analyses may help transmission providers and stakeholders to better understand the potential impact of Long-Term Regional Transmission Facilities on the transmission system, as well as the costs and benefits of Long-Term Regional Transmission Facilities. Particularly, consistent with the flexibility the Commission provided in Order No. 1920 as to cost allocation methods for Long-Term Regional Transmission Facilities (or portfolios of such Facilities), we find that additional analyses may help inform the application of *ex ante* Long-Term Regional Transmission Cost Allocation Methods or the development of cost allocation methods through the State Agreement Process.

[1016] The use of "scenarios" in this context indicates that these analyses are not required to meet Order No. 1920's requirements as to the development of Long-Term Scenarios and therefore are not "Long-Term Scenarios" within the meaning provided in Order No. 1920.

366. We further clarify that, when developing these additional analyses or scenarios used to inform cost allocation, transmission providers have the flexibility to depart from Order No. 1920's requirements related to the development of Long-Term Scenarios. For example, transmission providers may develop scenarios that consider the incremental cost and benefits of Long-Term Regional Transmission Facilities needed to achieve state laws, policies, and regulations beyond the cost and benefits of Long-Term Regional Transmission Facilities needed in the absence of those laws, policies, and regulations. Finally, as discussed below, we clarify that, if the Relevant State Entities wish for the transmission provider to develop a reasonable number of additional scenarios for Long-Term Regional Transmission Planning or Long-Term Regional Cost Allocation, then the transmission providers will develop these scenarios. While transmission providers may conduct such additional analyses, additional analyses that do not meet Order No. 1920's Long-Term Scenario requirements are not considered Long-Term Scenarios as defined in Order No. 1920.[1017] In other words, transmission providers may not use any such additional analyses to identify Long-Term Transmission Needs, identify Long-Term

[1017] Generally, to comply with Order No. 1920, including as clarified herein, transmission providers must develop at least three Long-Term Scenarios and perform at least one sensitivity analysis for each such Long-Term Scenario; identify Long-Term Transmission Needs using those Long-Term Scenarios and sensitivities thereto; identify Long-Term Regional Transmission Facilities (or portfolios of Long-Term Regional Transmission Facilities) that meet the identified Long-Term Transmission Needs; use and measure the seven required benefits of Long-Term Regional Transmission Facilities within those Long-Term Scenarios and sensitivities; otherwise evaluate those Long-Term Regional Transmission Facilities in the manner prescribed by Order No. 1920; and make a selection decision as to the Long-Term Regional Transmission Facilities identified and evaluated by transmission providers.

Regional Transmission Facilities, or to meet the requirement that transmission providers estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities for purposes of selection (i.e., to apply the transmission provider's selection criteria). Transmission providers also may not, consistent with the requirement that transmission providers have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs, condition the selection of a Long-Term Regional Transmission Facility on the information provided in these additional analyses.

367. Next, we clarify that, when requested by Relevant State Entities in a transmission planning region, transmission providers are required to conduct a reasonable number of additional analyses or scenarios. On compliance, transmission providers may propose processes to determine when Relevant State Entities have requested additional analyses and how to determine what a reasonable number of additional analyses may be.[1018] We reiterate that any cost allocation method—whether an *ex ante* Long-Term Regional Transmission Cost Allocation Method or a cost allocation method developed through the State Agreement Process for a specific Long-Term Regional Transmission Facility or

[1018] For example, in Order No. 890, the Commission required that stakeholders be given the right to request that transmission providers conduct a certain number of economic planning studies, to be determined on a regional basis, and the Commission offered the "merely illustrative" example of five to ten such studies. Order No. 890, 118 FERC ¶ 61,119 at P 547 & n.323.

portfolio thereof— that results from such additional analyses or scenarios must satisfy the cost causation principle.[1019]

368. Finally, in response to the request for rehearing from PJM related to sensitivity analyses required by Order No. 1920 to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area, we disagree with the arguments on rehearing and decline to provide clarification. We continue to find that Order No. 1920's requirements in this regard are necessary to ensure just and reasonable Commission-jurisdictional rates. In particular, extreme weather events have occurred more frequently in recent years, represent periods during which regional transmission facilities have particularly high value, and create stressed system conditions that transmission providers can readily compare with non-stressed scenarios to determine the value of specific transmission facilities under these types of conditions.[1020] PJM did not provide adequate information to explain why additional flexibility in developing sensitivities for each Long-Term Scenario is necessary, and we are unconvinced that PJM's regional circumstances justify

[1019] Order No. 1920, 187 FERC ¶ 61,068 at PP 1472, 1477.

[1020] *Id.* P 596. *See also Transmission Sys. Plan. Performance Requirements for Extreme Weather*, Order No. 896, 88 FR 41262 (June 23,2023), 183 FERC ¶ 61,191, at P 2 (2023) (explaining that extreme heat and cold weather events have occurred more frequently in recent years); *One-Time Informational Reps. on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, & Elec. Sys. Reliability*, Order No. 897, 88 FR 41477 (June 27, 2023), 183 FERC ¶ 61,192, at P 2 (2023) (same).

flexibility on this issue. To the extent that PJM's regional circumstances require other specific sensitivities, we reiterate that we encourage transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.[1021]

### C. Evaluation of the Benefits of Regional Transmission Facilities

#### 1. Requirement for Transmission Providers to Use and Measure a Set of Seven Required Benefits

##### a. Order No. 1920 Requirements

369. In Order No. 1920, the Commission required transmission providers in each transmission planning region to measure a set of seven required benefits (required benefits) for Long-Term Regional Transmission Facilities under each Long-Term Scenario and to use these measured benefits to evaluate Long-Term Regional Transmission Facilities.[1022] The Commission required transmission providers to measure and use the following required benefits in Long-Term Regional Transmission Planning: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages;

[1021] Order No. 1920, 187 FERC ¶ 61,068 at P 597.

[1022] Order No. 1920, 187 FERC ¶ 61,068 at P 719.

(6) mitigation of extreme weather events and unexpected system conditions; and

(7) capacity cost benefits from reduced peak energy losses.[1023]

370. The Commission found that the record demonstrated that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it was necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. Further, the Commission found that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning could not be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.[1024] The Commission concluded that requiring the measurement and use of the seven required benefits in Long-Term Regional Transmission Planning ensured that transmission providers will consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. In contrast, the Commission found that not

[1023] *Id.* P 720.

[1024] *Id.* P 722.

requiring transmission providers to use any specific benefits in Long-Term Regional Transmission Planning, as proposed in the NOPR, would fail to ensure that transmission providers consider the broader set of benefits provided by, and the beneficiaries receiving the benefits of, Long-Term Regional Transmission Facilities, and, thus, may fail to identify the potentially more efficient or cost-effective regional transmission solution(s) to specific Long-Term Transmission Needs.[1025]

371. The requirement that transmission providers measure and use the required benefits in Long-Term Regional Transmission Planning was a change from the NOPR proposal.[1026] In the NOPR, the Commission did not propose to require the use of any specific benefits and instead acknowledged the benefits of regional flexibility, and consistent with Order No. 1000, proposed to consider such matters on review of compliance proposals.[1027] The NOPR included a non-exhaustive list of 12 benefits[1028] that the Commission stated could be considered by transmission providers in Long-Term Regional Transmission Planning and cost allocation processes.[1029] The Commission also sought comment on "whether public utility transmission providers should be required to

[1025] *Id.* P 723.

[1026] *Id.*

[1027] NOPR, 179 FERC ¶ 61,028 at P 183 (citation omitted).

[1028] *Id.* P 185.

[1029] *Id.* P 184.

use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process."[1030]

**b. Logical Outgrowth**

**i. Requests for Rehearing and Clarification**

372. East Kentucky and NRECA argue that Order No. 1920 violates the APA's notice-and-comment requirements because it mandates that transmission providers use a set of seven benefits for evaluating Long-Term Regional Transmission Facilities, a requirement that East Kentucky and NRECA argue is not a logical outgrowth of the NOPR, which proposed non-mandatory and non-exhaustive examples of benefits that transmission providers could use.[1031] NRECA asserts that the NOPR made clear that the list of potential benefits was neither mandatory nor exhaustive and that transmission providers would have flexibility to determine what benefits they use in their Long-Term Regional Transmission Planning.[1032] NRECA describes the final rule's seven required benefits as "nationwide, mandatory, [and] one-size-fits all" and the "exact opposite" of the proposed rule.[1033]

[1030] *Id.* P 188.

[1031] East Kentucky Rehearing Request at 1-2 (citing 5 U.S.C. 553(b)); NRECA Rehearing Request at 4, 10-13 (citing 5 U.S.C. 553(b)).

[1032] NRECA Rehearing Request at 10 (quoting NOPR, 179 FERC ¶ 61,028 at P 183).

[1033] *Id.* at 11.

### ii. Commission Determination

373. We disagree with the argument that the Commission failed to provide adequate notice and opportunity to comment on Order No. 1920's requirement that transmission providers measure a set of seven required benefits for Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of Long-Term Regional Transmission Planning and use these measured benefits to evaluate Long-Term Regional Transmission Facilities.[1034] As courts have explained, "[n]otice suffices when [an agency] has 'expressly asked for comments on a particular issue or otherwise made clear that the agency was contemplating a particular change.'"[1035] NRECA acknowledges that the NOPR sought comment on whether transmission providers should be required to use some or all of the potential benefits described in the NOPR as a minimum set of benefits for their Long-Term Regional Transmission Planning process.[1036] By requesting comment on whether to make mandatory some or all of the benefits in the NOPR, the Commission sufficiently put parties on notice that the Commission was considering *the exact change* that East Kentucky and NRECA now argue was unanticipated and violated the APA's notice-and-comment requirements. Thus, in adopting the requirement that transmission providers measure and use the set of seven required benefits in Long-Term

[1034] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 719.

[1035] *Brennan v. Dickson*, 45 F.4th 48, 69 (D.C. Cir. 2022) (quoting *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1081 (D.C. Cir. 2009)).

[1036] *See* NRECA Rehearing Request at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 188).

Regional Transmission Planning, the Commission adhered to the APA's notice-and-comment requirements.

### c. Flexibility Regarding Benefits Rather than a Minimum Set

#### i. Requests for Rehearing and Clarification

374. Dominion requests rehearing and argues that the seven required benefits are not directly tied or correlated to the seven categories of factors establishing Long-Term Transmission Needs.[1037] Dominion contends that the seven required benefits "are generic, almost inherent benefits of all transmission," whereas the seven categories of factors that transmission providers must incorporate in the development of Long-Term Scenarios "are mostly restatements of public policy driven needs for transmission facilities."[1038] Dominion states that it "is not suggesting that Factor Category No. 1 must match Benefit No. 1, etc.; rather, individually, and as a whole, the[] seven Factor Categories do not correlate to any or all of the seven Benefits."[1039] Dominion opines that, because the seven required benefits do not correspond to the seven categories of factors, regardless of the public policy issues driving the need for a transmission facility, Order No. 1920's requirement that transmission providers use the seven required benefits in determining whether to select a transmission facility will likely result in a public policy

[1037] Dominion Rehearing Request at 18.

[1038] *Id.* at 20.

[1039] *Id.* at 19 n.83.

project always being selected.[1040] Further, Dominion opines that, because the seven required benefits do not correspond to the seven categories of factors, the seven required benefits are "secondary or incidental" to the primary purpose of the Long-Term Regional Transmission Facilities. Dominion states that the United States Court of Appeals for the Seventh Circuit "rejected the use of 'incidental' benefits because 'the incidental-benefits tail mustn't be allowed to wag the primary-benefits dog.'"[1041] Dominion contends that Order No. 1920 should have required that Long-Term Transmission Needs and the benefits of Long-Term Regional Transmission Facilities correspond to each other, and failure to impose such a requirement was not reasoned decision making.[1042] Dominion states that the Commission should provide flexibility to transmission providers to allow them to identify the benefits that they will measure in their compliance filings and ensure that those benefits are tied to the underlying needs.[1043]

375. PJM requests rehearing and argues that Order No. 1920 is arbitrary and capricious because the requirement that transmission providers measure and use seven required benefits to evaluate Long-Term Regional Transmission Facilities is an unexplained departure from the NOPR's recognition of the value of allowing regional flexibility with

[1040] *Id.* at 20.

[1041] *Id.* (alteration omitted) (quoting *ICC v. FERC III*, 756 F.3d at 564).

[1042] *Id.*

[1043] *Id.* at 18-19, 21.

respect to benefits.[1044] PJM argues that the Commission should provide flexibility to transmission providers to allow them to identify the benefits that they will measure in their compliance filings (except for Final Rule Benefits 1, 2, and 3, which PJM agrees should be required).[1045] PJM asserts that Final Rule Benefits 4 and 5 are additional benefits that RTOs could add as they gain experience and determine to be quantitatively important. PJM also argues that Final Rule Benefit 6 has three different subcomponents and could be very cumbersome to measure if each one of them must be quantified.[1046]

376. Designated Retail Regulators and Undersigned States request rehearing and assert that the benefit metrics used to evaluate Long-Term Regional Transmission Facilities should be developed as part of RTO stakeholder processes, not mandated by the Commission.[1047] NRECA alleges that by prescribing the required benefits that transmission providers must use for evaluation and selection of Long-Term Regional Transmission Facilities, the final rule will likely change the results of the evaluation and selection processes in unanticipated ways.[1048]

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[1044] PJM Rehearing Request at 5, 26-27 & n.106.

[1045] *Id.* at 26-29, 42.

[1046] *Id.* at 29.

[1047] Designated Retail Regulators Rehearing Request at 29; Undersigned States Rehearing Request at 29.

[1048] NRECA Rehearing Request at 11-12.

### ii. Commission Determination

377. We are not persuaded by arguments raised on rehearing that the Commission should not require transmission providers to use and measure the seven required benefits. We continue to find that allowing transmission providers to determine which benefits they will use and measure, rather than requiring the measurement and use of a minimum set of benefits, may result in transmission providers not measuring important potential benefits of Long-Term Regional Transmission Facilities.[1049] This, in turn, would not resolve the deficiencies that the Commission identified in the final rule, such as transmission providers failing to adequately consider the benefits of regional transmission facilities and thereby not selecting the more efficient or cost-effective solutions, leading to unjust and unreasonable Commission-jurisdictional rates.[1050] Additionally, as the Commission noted in Order No. 1920, requiring transmission providers to measure and

[1049] Order No. 1920, 187 FERC ¶ 61,068 at PP 723-724.

[1050] *See id.* P 123 ("Failing to adequately identify and consider the benefits of [Long-Term Regional Transmission Facilities] may lead to relatively inefficient or less cost-effective transmission development. In particular, the cost-benefit analyses that transmission providers often use as part of the evaluation process may fail to identify more efficient or cost-effective regional transmission facilities for selection because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities. Thus, the failure to adequately consider the benefits of regional transmission facilities results in, among other things, transmission customers forgoing benefits that may significantly outweigh their costs, which results in less efficient or cost-effective transmission investments and, in turn, contributes to Commission-jurisdictional rates that are unjust and unreasonable."); *id.* P 723.

use a required set of benefits will help improve interregional transmission coordination among different transmission planning regions.[1051]

378. We disagree with Dominion's argument that Order No. 1920 does not constitute reasoned decision making or is arbitrary and capricious because the seven required benefits are not tied or correlated to the seven categories of factors that Order No. 1920 requires transmission providers to incorporate into the development of Long-Term Scenarios. We understand Dominion's argument to be that, even though Long-Term Regional Transmission Facilities address Long-Term Transmission Needs that are driven primarily by the incorporation of certain categories of factors that Dominion considers to be "public policy issues," the required benefits, which Dominion contends are designed to measure a broader range of benefits of transmission facilities unrelated to public policy-related factors, will likely result in a public policy project always being selected. We disagree with this argument. We first note that Dominion provides only speculation that such a result will occur. As the Commission found in Order No. 1920, while state policies make up some of the drivers of Long-Term Transmission Needs, they do not comprise the entirety of those drivers.[1052] Accordingly, Long-Term Transmission Needs will be driven by factors (e.g., resource retirements and trends in fuel costs) in addition to

[1051] *Id.* P 729 (citations omitted).

[1052] *Id.* P 1478. The Commission recognized that state policy goals do not necessarily need to be given the same weight as state laws and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios because government entities have an interest and ability to ensure that the requirements of state laws and regulations are fully achieved. *Id*. PP 512, 516.

and unrelated to "public policy issues," and Long-Term Transmission Facilities will likely be designed to address multiple Long-Term Transmission Needs. In any case, Order No. 1920 does not require that transmission providers select any particular Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria,[1053] which this order maintains on rehearing.[1054]

379. We disagree with Dominion's assertion that the seven required benefits are "secondary or incidental" to Long-Term Transmission Needs. As the Commission explained in Order No. 1920, the drivers of transmission needs are diverse and include, but are not limited to, grid reliability, changes in the resource mix, and increased demand for electricity.[1055] As discussed in the Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs section above, we clarify in this order that Long-Term Transmission Needs as defined in Order No. 1920 are driven by both reliability and economic considerations and, as such, both reliability and economic considerations must inform transmission providers' identification of Long-Term Transmission Needs. The seven required benefits measure distinct, well-understood benefits of potential Long-Term

[1053] *Id.* P 1026 (citations omitted).

[1054] *See infra* No Selection Requirement section.

[1055] Order No. 1920, 187 FERC ¶ 61,068 at P 299. *See also id.* PP 39, 299 (defining Long-Term Transmission Needs as "transmission needs identified through Long-Term Regional Transmission Planning by, among other things . . . running scenarios and considering the enumerated categories of factors").

Regional Transmission Facilities and are well supported in the record.[1056] Because the seven required benefits reflect many of the reliability and economic benefits that Long-Term Regional Transmission Facilities can provide, we disagree with Dominion that such benefits are secondary or incidental to Long-Term Transmission Needs. Further, the Commission noted in Order No. 1920 that, "[w]e find that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs."[1057] The Commission also stated that "[b]y requiring the measurement and use of the seven enumerated benefits in Long-Term Regional Transmission Planning, we ensure that transmission providers will consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional

[1056] *Id.* P 724 (noting that the seven required benefits "have a proven track record"); *id.* P 746 (Final Rule Benefit 1), PP 749-750 (Final Rule Benefit 2), P 761 (Final Rule Benefit 3), P 782 (Final Rule Benefit 4), P 784 (Final Rule Benefit 5), P 791 (Final Rule Benefit 6), P 812 (Final Rule Benefit 7); *see also id.* P 731 ("[A]ll seven required benefits have either been approved for use in regional transmission planning in at least one non-RTO/ISO transmission planning region or may be implemented by building upon the modeling or techniques used to measure benefits in RTO/ISO or non-RTO/ISO regions, or both."); *id.* P 732 (explaining that the Commission has accepted the use of several of the seven benefits to evaluate transmission facilities and projects).

[1057] *Id.* P 722.

Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs."[1058]

380. Finally, the Commission found in Order No. 1920, and we continue to find here, that transmission providers must measure, at a minimum, this set of seven required benefits and then use them to evaluate Long-Term Regional Transmission Facilities in order to ensure just and reasonable rates.[1059] The Commission noted:

> The record in this proceeding shows that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it is necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. We find that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.[1060]

[1058] *Id.* P 723.

[1059] *Id.* P 721.

[1060] *Id.* P 722.

381. Indeed, as Dominion concedes, the seven benefits that Order No. 1920 requires transmission providers to use and measure when evaluating Long-Term Regional Transmission Facilities are "inherent benefits of all transmission."[1061]

382. In addition, we disagree with PJM's assertion that Order No. 1920 is arbitrary and capricious because the requirement that transmission providers measure and use seven required benefits to evaluate Long-Term Regional Transmission Facilities is an unexplained departure from the NOPR's recognition of the value of allowing regional flexibility with respect to benefits. We continue to find that the requirement for transmission providers to measure and use the minimum set of seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1062] Specifically, absent a requirement that transmission providers measure and use a sufficiently broad range of the benefits of Long-Term Regional Transmission Facilities when evaluating them for potential selection, transmission providers may not identify, evaluate, and select more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs, which may lead to relatively inefficient or less cost-effective transmission development. Therefore, we find that allowing the regional flexibility that PJM suggests would fail to remedy the deficiencies in existing regional transmission planning and cost allocation processes – namely, the failure to require transmission providers to adequately consider

[1061] Dominion Rehearing Request at 20.

[1062] Order No. 1920, 187 FERC ¶ 61,068 at P 727.

the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs[1063] – that the Commission identified in the final rule.[1064] We also note that PJM itself previously recognized that certain benefits should be required; in its comments on the NOPR, PJM called for the adoption of a nationwide consideration of

[1063] *Id.* P 122.

[1064] Contrary to PJM's assertion, in Order No. 1920 the Commission explained its reasons for not adopting the more flexible approach proposed in the NOPR. The Commission found:

> [A]dopting the more flexible approach proposed in the NOPR would not address the identified deficiencies in existing regional transmission planning and cost allocation processes because such an approach would fail to ensure that transmission providers consider the broader set of benefits provided by, and the beneficiaries receiving the benefits of, Long-Term Regional Transmission Facilities, and thus, may fail to identify the potentially more efficient or cost-effective regional transmission solution. We find that failing to use the set of benefits that we require in this final rule to evaluate Long-Term Regional Transmission Facilities for potential selection could render resulting Commission-jurisdictional rates unjust and unreasonable. We find that not requiring transmission providers to use certain benefits to evaluate Long-Term Regional Transmission Facilities would be expected to lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected.

*Id.* P 723; *see also id.* P 728 ("We conclude that it would be inappropriate to provide flexibility not to consider this required set of benefits in Long-Term Regional Transmission Planning because . . . requiring the measurement and use of these benefits ensures that transmission providers are able to identify, evaluate, and select regional transmission solutions to more efficiently or cost-effectively address Long-Term Transmission Needs, and thereby ensures just and reasonable rates.").

benefits that are similar to certain benefits that the Commission adopted in Order No. 1920 as part of the set of seven required benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning.[1065]

383. In response to Designated Retail Regulators' and Undersigned States' requests for flexibility to establish the benefits for transmission providers to measure through RTO/ISO stakeholder processes, we reiterate that the measurement and use of certain benefits in Long-Term Regional Transmission Planning is essential to ensuring just and reasonable Commission-jurisdictional rates.[1066] As such, we find that it is necessary for the Commission to mandate the measurement and use of these benefits – the required benefits – in Long-Term Regional Transmission Planning rather than deferring to RTO/ISO stakeholder processes.[1067]

384. We also are not persuaded by NRECA's assertion that, by prescribing the required benefits that transmission providers must use for evaluation and selection of Long-Term Regional Transmission Facilities, the final rule will likely change the results of the evaluation and selection processes in unanticipated ways. NRECA does not explain what

[1065] PJM NOPR Initial Comments at 96 ("[T]he following benefit categories should be considered on a nationwide basis: (i) Enhanced Reliability; (ii) Avoided or Deferred Reliability Transmission Projects and Aging Infrastructure Replacement; (iii) Deferred Capacity Investment; and (iv) Production Cost Savings.").

[1066] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 722-723, 725, 727-728.

[1067] *Id.* PP 723, 728.

unanticipated consequences it foresees arising, and we find this assertion speculative and unsupported.

### d. Overlap and Double-Counting

#### i. Order No. 1920 Requirements

385. In Order No. 1920, the Commission noted that, "rather than requiring transmission providers to measure and use all 12 benefits enumerated in the NOPR, we only require transmission providers to measure and use seven specific benefits that have a proven track record, can be discretely measured, and are unlikely to cause duplication."[1068] In response to concerns raised by commenters regarding the potential for overlap and double-counting, the Commission further noted:

> We believe that the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting. Nonetheless, to the extent that transmission providers are concerned that any possibility of double-counting remains, we provide transmission providers with flexibility on the measurement of such benefits and expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address those concerns.[1069]

386. With respect to Final Rule Benefit 3, Production Cost Savings, the Commission in Order No. 1920 explained why it did not believe that this benefit would result in double-counting of benefits merely because such benefits may also be considered in state

[1068] *Id.* P 724.

[1069] *Id.* P 735.

resource planning.[1070] Specifically, the Commission found that while integrated resource planning processes, where they exist, may consider similar benefits compared to those required by Order No. 1920, the consideration of benefits in a state-jurisdictional process does not result in the double-counting of benefits within any Commission-jurisdictional transmission planning process.[1071]

387. The Commission in Order No. 1920 also offered guidance regarding the manner of measurement of certain aspects of Final Rule Benefit 6, mitigation of extreme weather events and unexpected system conditions, to avoid double-counting. The Commission noted, for example, that "to avoid double-counting of similar circumstances, transmission providers must account for extreme weather events and unexpected system conditions that are separate and distinct such that the benefits of mitigating each system condition can be combined into a single benefit measure."[1072]

### ii. Requests for Rehearing and Clarification

388. Designated Retail Regulators and Undersigned States request rehearing and assert that Order No. 1920's requirements to use seven required factors and seven required benefits will result in unjust and unreasonable rates. They argue that the seven required factors and seven required benefits overlap and will double-count or exaggerate the

[1070] *Id.* P 770.

[1071] *Id.*

[1072] *Id.* P 804.

potential benefits of Long-Term Regional Transmission Facilities, with Undersigned States adding that this renders the rule arbitrary and capricious.[1073]

389. Designated Retail Regulators and Undersigned States assert that with respect to the seven required benefits, it is unclear whether these metrics will result in double-counting of potential benefits.[1074]

### iii. Commission Determination

390. We disagree with Designated Retail Regulators and Undersigned States that the seven required benefits will overlap and will double-count or exaggerate the potential benefits of Long-Term Regional Transmission Facilities. As an initial matter, the Commission found in Order No. 1920, and we continue to find here, that "the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting."[1075] Designated Retail Regulators and Undersigned States fail to provide evidence in support of their arguments

[1073] Designated Retail Regulators Rehearing Request at 8 (citation omitted); Undersigned States Rehearing Request at 8 (citation omitted).

[1074] Designated Retail Regulators Rehearing Request at 29; Undersigned States Rehearing Request at 29.

[1075] Order No. 1920, 187 FERC ¶ 61,068 at P 735. As noted above, the Commission also addressed arguments relating to double-counting and/or overlap between Final Rule Benefit 3 and integrated resource planning processes and provided guidance regarding the manner of measurement of certain aspects of Final Rule Benefit 6, mitigation of extreme weather events and unexpected system conditions, to avoid double-counting.

to the contrary, and they do not provide any specific examples of the alleged overlap. Given the descriptions of the required benefits adopted in Order No. 1920,[1076] we conclude that each of these required benefits captures a different type of benefit that Long-Term Regional Transmission Facilities may provide. However, we reiterate, as the Commission stated in the final rule, that Order No. 1920 provides transmission providers with flexibility on the measurement of the required benefits, and we expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address any concerns about the possibility of double-counting benefits.[1077]

391. Moreover, the Commission explained in Order No. 1920 that transmission providers' evaluation of Long-Term Regional Transmission Facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) was selected or not selected.[1078] The Commission also explained that this determination must include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) that transmission providers evaluated in the Long-Term Regional Transmission Planning process, regardless of whether or not the Long-

[1076] *Id.* PP 745, 756, 758, 767, 781, 788, 800, 817.

[1077] *Id.* P 735.

[1078] *Id.* P 954.

Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[1079] We find that these requirements will further safeguard against potential overlap and double-counting of benefits.

392. With respect to Undersigned States' and Designated Retail Regulators' concerns regarding the relationship between benefits and factors, we address this issue in the Requirement for Transmission Providers to Use the Seven Required Benefits to Help to Inform Their Identification of Long-Term Transmission Needs section above. As noted there, we are setting aside Order No. 1920's requirement for transmission providers to use the set of seven required benefits to help to inform their identification of Long-Term Transmission Needs. As such, we find that there is no overlap between the categories of factors that transmission providers must incorporate into the development of Long-Term Scenarios, which are developed prior to the identification of Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to address those needs, and the required benefits, which are subsequently used to evaluate the identified Long-Term Regional Transmission Facilities.

393. With respect to Designated Retail Regulators' and Undersigned States' concerns about potential overlaps between the seven required benefits and other benefits that transmission providers may use and measure, we find that Order No. 1920 provides for sufficient transparency to prevent any such overlap. Specifically, Order No. 1920 requires transmission providers to describe how they will measure the seven required

[1079] *Id.* PP 954, 966.

benefits in OATT filings.[1080] Additionally, it requires transmission providers to measure and use any additional benefits beyond those included in the required set of benefits, including on a transmission facility or plan-specific basis, in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.[1081] As such, stakeholders will have the information necessary to identify any potential double-counting of the required benefits and any other benefits that transmission providers choose to measure and use in Long-Term Regional Transmission Planning.

**e. Conflicts with State Authority**

**i. Requests for Rehearing and Clarification**

394. Designated Retail Regulators assert that the seven required benefits conflict with the state authority reflected in both the transmission planning principles adopted by OMS that project metrics should be quantifiable, subject to accurate measurement, verifiable, non-duplicative, and forward looking and the Entergy Regional State Committee's adoption of "even more stringent requirements to ensure that any metrics adopted reflected actual, not hypothetical, value that would justify major transmission investment."[1082] For instance, Designated Retail Regulators state that the Entergy

[1080] *Id.* P 837.

[1081] *Id.* P 822.

[1082] Designated Retail Regulators Rehearing Request at 31-33 (citing Organization of MISO States, Inc., *Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects*, https://www.misostates.org/images/PositionStatements/OMS_Position_Statement_of_Pri

Regional State Committee (E-RSC) adopted stringent requirements to ensure that any metrics adopted reflected actual, not hypothetical, value that would justify major transmission investment:

> The cost-benefit and other analyses that are used to inform the business case and cost allocation for Tranche 3 shall be based only on accurate, objective, measurable, quantifiable, non-duplicative, forward-looking, and replicable metrics that are supported by data;
>
> Tranche 3 costs shall be allocated using an exclusive list of benefit metrics identified by the E-RSC, with advice from MISO and MISO South Stakeholders, that meet the criteria identified in Paragraph 3 above. These metrics shall be memorialized after being approved by the E-RSC;
>
> Each Tranche 3 project must individually satisfy the cost-benefit analysis used for the business case and cost allocation on a stand-alone basis. Where two or more transmission facility upgrades combine to address a specific transmission issue, they may be evaluated as a single project for the purpose of analysis and cost allocation.[1083]

395. NESCOE requests that the Commission grant rehearing to require transmission providers to defer to states in the identification of benefits that Long-Term Regional Transmission Facilities may provide when the driver of the Long-Term Transmission Need is related to satisfying state laws, regulations, or policies.[1084]

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nciples_Cost_Allocation_for_LRTPs.pdf).

[1083] Designated Retail Regulators Rehearing Request at 32-33 (quoting Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee*, 3 (adopted June 30, 2023), https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf).

[1084] NESCOE Rehearing Request at 11 (citation omitted).

### ii. Commission Determination

396. We are not persuaded by requests for rehearing that argue that the Commission's establishment of a set of required benefits in Order No. 1920 impermissibly or improperly intrudes upon state authority. We continue to find that, while the Long-Term Regional Transmission Planning required in Order No. 1920 may be more comprehensive than the status quo, as a matter of the Commission's jurisdiction, it is fundamentally no different than the regional transmission planning already required by the Commission and upheld by the appellate courts.[1085] Using the required benefits to evaluate Long-Term Regional Transmission Facilities is an incremental improvement to the Commission's Order No. 890 and Order No. 1000 reforms requiring processes for evaluating the merits of proposed transmission solutions offered by potential developers.[1086] The D.C. Circuit upheld the Commission's Order No. 1000 regional transmission planning reforms against challenges rooted in similar misunderstandings of the Commission's jurisdiction as those advanced by the rehearing parties.[1087]

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[1085] Order No. 1920, 187 FERC ¶ 61,068 at P 277 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 68-69).

[1086] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 315 (citing Order No. 890, 118 FERC ¶ 61,119 at P 494; Order No. 890-A, 121 FERC ¶ 61,297 at PP 215-216).

[1087] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 63 ("Taken together, these points support the Commission's assertion of authority over transmission planning matters in the challenged orders, notwithstanding petitioners' contention that the orders intrude on the States' authority.").

397. Further, we reiterate the Commission's finding in Order No. 1920 that some benefits are so essential to Long-Term Regional Transmission Planning that they must be required and not left to the discretion of stakeholders, whether RTOs/ISOs or state committees.[1088] Order No. 1920, for example, found that requiring the measurement and use of Final Rule Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement, as described, is necessary because Long-Term Regional Transmission Facilities may obviate or delay the need for reliability transmission facilities identified in the near term, or the need for later replacements of aging transmission infrastructure.[1089] Moreover, as discussed in the Flexibility Regarding Benefits Rather than a Minimum Set section above, the Commission found in Order No. 1920 that the requirement for transmission providers to measure and use the seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1090] We sustain this finding and, as a result, continue to find that the measurement and use of these minimum set of required benefits in Long-Term Regional Transmission Planning cannot be left to the discretion of transmission providers or stakeholders.

398. We also question the degree of intrusion cited by certain rehearing parties. We note, for example, that many of the OMS and Entergy Regional State Committee

[1088] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 722-723, 725, 728.

[1089] *Id.* P 745.

[1090] *Id.* P 727.

transmission planning principles cited by Designated Retail Regulators are similar to provisions governing the measurement and use of the required benefits in Order No. 1920. For example, Order No. 1920's findings and requirements with respect to the seven required benefits are consistent with the second of OMS's transmission planning principles[1091] that benefit metrics be quantifiable,[1092] capable of replication,[1093] non-duplicative,[1094] and forward-looking.[1095]

399. With respect to Designated Retail Regulators' assertions regarding the Entergy Regional State Committee requirements, we note that many of the metrics for analysis

[1091] Organization of MISO States, Inc., *Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects*, https://www.misostates.org/images/PositionStatements/OMS_Position_Statement_of_Principles_Cost_Allocation_for_LRTPs.pdf.

[1092] Order No. 1920, 187 FERC ¶ 61,068 at P 724 ("[W]e only require transmission providers to measure and use seven specific benefits that . . . can be discretely measured.").

[1093] *Id.* P 837 ("[We] require transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the seven benefits included in the required set of benefits . . . .").

[1094] *Id.* P 735 ("We believe that the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting.").

[1095] *Id.* P 859 ("[We] require transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities . . . .").

raised by the first cited requirement[1096] are similar to those required by the final rule and by OMS. With respect to the second requirement ("Tranche 3 costs shall be allocated using an exclusive list of benefit metrics identified by the E-RSC"), we note that transmission providers are free to measure and use additional benefits in Long-Term Regional Transmission Planning so long as they also measure and use the required benefits and measure and use any other benefits in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.[1097] With respect to the third requirement,[1098] the final rule noted the potential to use cost-benefit metrics as a means for evaluating and selecting Long-Term Regional Transmission Facilities.[1099]

[1096] Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee*, at 3 (adopted June 30, 2023), https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf ("The cost-benefit and other analyses that are used to inform the business case and cost allocation for Tranche 3 shall be based only on accurate, objective, measurable, quantifiable, non-duplicative, forward-looking, and replicable metrics that are supported by data.").

[1097] Order No. 1920, 187 FERC ¶ 61,068 at P 822.

[1098] Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee*, at 3 (adopted June 30, 2023), https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf ("Each Tranche 3 project must individually satisfy the cost-benefit analysis used for the business case and cost allocation on a stand-alone basis.")

[1099] Order No. 1920, 187 FERC ¶ 61,068 at P 966 (noting that transmission provider evaluation processes must result in determinations that "include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) evaluated by the transmission providers, whether or not the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is

400. We are also unpersuaded by NESCOE's request that we defer to state preferences regarding benefits when the driver of the Long-Term Transmission Need is related to satisfying state laws, regulations, or policies. As noted above, the measurement and use of the required benefits in Long-Term Regional Transmission Planning is essential to ensuring just and reasonable Commission-jurisdictional rates such that the Commission cannot defer to states on this point. However, we note that Order No. 1920 requires consultation with the states regarding aspects of Long-Term Regional Transmission Planning, including a requirement that transmission providers consult with and seek the support of Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional Transmission Facilities and that provide transmission providers with the opportunity to select Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs, including those related to satisfying state laws, regulations, or policies.[1100] Further, as clarified in this order in the Stakeholder Process and Transparency section above, transmission providers must provide states with a meaningful opportunity to provide timely input on the development of Long-Term Scenarios, including factors and data inputs, and an opportunity to explain how their own policies and planning affect Long-Term Transmission Needs.[1101]

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selected").

[1100] *See id.* PP 914, 994.

[1101] Further, as discussed in the General Benefits Requirements Related to Cost Allocation section below, transmission providers can consider additional benefits for cost

### f. Individual Benefits

#### i. Final Rule Benefit 2(a): Reduced Loss of Load Probability; or Final Rule Benefit 2(b): Reduced Planning Reserve Margin

##### (a) Order No. 1920 Requirements

401. With respect to Final Rule Benefit 2, the Commission stated that this benefit can be characterized and measured as Final Rule Benefit 2(a), Reduced Loss of Load Probability, or as Final Rule Benefit 2(b), Reduced Planning Reserve Margin, two different methods for measuring the same underlying benefit. The Commission found that because there is an overlap between the reduced loss of load probability benefits and reduced planning reserve margin benefits, for purposes of Long-Term Regional Transmission Planning, transmission providers must either measure reduced loss of load events by holding the planning reserve margin constant *or* measure the reduction in planning reserve margins by holding loss of load events constant but may not measure both simultaneously for purposes of using and measuring Final Rule Benefit 2(a) or 2(b).[1102]

##### (b) Requests for Rehearing and Clarification

402. SERTP Sponsors argue that the Commission should clarify that it does not intend to require transmission providers to establish a planning reserve margin other than the

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allocation purposes, including, but not limited to, those agreed to by Relevant State Entities and described elsewhere in Order No. 1920, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

[1102] Order No. 1920, 187 FERC ¶ 61,068 at P 755.

planning reserve margin established by the resource planners and load-serving entities on that transmission provider's system. SERTP Sponsors also assert that the Commission should clarify that any analysis under Final Rule Benefit 2 should not be used as a basis to challenge the planning reserve margin of a resource planner or load-serving entity established through state resource planning processes, and that the use of such an analysis is only intended for the purpose of evaluating potential Long-Term Regional Transmission Facilities that may under certain planning scenarios suggest a potential benefit.[1103]

**(c) Commission Determination**

403. We clarify that Order No. 1920 does not require transmission providers to establish a different planning reserve margin than the one established by resource planners or load-serving entities in a particular transmission provider's system, including in measuring Final Rule Benefit 2. We underscore here that any calculation of this benefit will only serve to support the benefits assessment of potential Long-Term Regional Transmission Facilities during the Long-Term Regional Transmission Planning process. While the Commission described examples of how transmission providers could measure certain benefits, the Commission did not require a specific measurement method for any of the required benefits.[1104] Further, the Commission noted that Final Rule Benefit 2 can be measured in one of two ways: (a) using reduced loss of load probability

[1103] SERTP Sponsors Rehearing Request at 18.

[1104] Order No. 1920, 187 FERC ¶ 61,068 at P 727.

*or* (b) reduced planning reserve margin.[1105] In light of this clarification, we need not reach SERTP Sponsors' alternative argument that, absent this clarification, Order No. 1920 would raise concerns that the Commission has exceeded its jurisdiction.[1106]

404. In response to SERTP Sponsors' request to clarify that any analysis under Final Rule Benefit 2 should not be used as the basis for challenging a resource planner's or load-serving entity's planning reserve margin established through state resource planning processes, we clarify that any state resource planning process is a separate process subject to state jurisdiction and is beyond the scope of Order No. 1920.

#### ii. Final Rule Benefit 3: Production Cost Savings

##### (a) Order No. 1920 Requirements

405. In Order No. 1920, the Commission required transmission providers in each transmission planning region to measure and use Final Rule Benefit 3 in Long-Term Regional Transmission Planning. The Commission described this benefit as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices.[1107]

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[1105] *Id.* P 748.

[1106] *See* SERTP Sponsors Rehearing Request at 18 n.46, 43 (Issue Statement 15) (citations omitted).

[1107] Order No. 1920, 187 FERC ¶ 61,068 at P 767.

406. In Order No. 1920, the Commission disagreed with the assertion made in comments that production cost savings may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion. The Commission stated that financial transmission rights are required in RTO/ISO markets and allow the market participant that owns the right to mitigate the congestion charge along an existing transmission path for the capacity of that path. The Commission further stated that a new transmission facility could reduce congestion and allow that market participant to purchase more electricity, exceeding the capacity of the transmission path for the financial transmission right, at a lower price. The Commission observed that this reduced congestion allows load to access lower cost resources and results in more efficient dispatch of resources and, thus, provides avoided production cost benefits that are distinct from the avoided congestion charges associated with financial transmission rights.[1108]

**(b) Requests for Rehearing and Clarification**

407. SERTP Sponsors argue that the Commission should clarify that production cost analysis from state-approved integrated resource plans may be used to the extent feasible to satisfy the requirement to consider Final Rule Benefit 3. SERTP Sponsors further argue that, in the event of conflict, state-regulated integrated-resource-plan planning must control in accordance with FPA section 201.[1109]

[1108] *Id.* P 773 (citations omitted).

[1109] SERTP Sponsors Rehearing Request at 19.

408. Designated Retail Regulators assert that the Commission was mistaken in stating that a load-serving entity may benefit from reduced production costs associated with transmission construction even when its congestion costs are fully hedged. Designated Retail Regulators argue that as congestion is eliminated by transmission construction, the value of the load-serving entity's financial transmission rights decreases, and the load-serving entity incurs additional transmission charges associated with the new transmission facilities. Designated Retail Regulators assert that any benefit based on adjusted production cost must therefore consider congestion to determine if a load-serving entity receives any benefit or harm from transmission construction.[1110]

**(c) Commission Determination**

409. In response to SERTP Sponsors, we note that Order No. 1920 does not require a specific measurement method for any of the seven required benefits. We clarify that if transmission providers in a transmission planning region believe they can use production cost savings from one or more state integrated resource plans as an appropriate method to measure the value of Final Rule Benefit 3, they may propose to do so on compliance. As a general matter, we agree that states have authority over generation resource adequacy, which may include evaluation of production cost savings in state-regulated integrated resource plans. Order No. 1920, however, addresses transmission planning practices directly affecting Commission-jurisdictional rates, including by requiring that transmission providers consider the broader set of benefits (such as Final Rule Benefit 3)

[1110] Designated Retail Regulators Rehearing Request at 30-31.

associated with Long-Term Regional Transmission Facilities. We therefore decline SERTP Sponsors' request to clarify that transmission providers must, in all circumstances, rely on such state evaluations of production cost savings in assessing the benefits associated with such facilities.[1111]

410. We decline Designated Retail Regulators' request for clarification regarding Final Rule Benefit 3 with respect to financial transmission rights. We continue to find that financial transmission rights allow the market participant that owns the right to mitigate the congestion charge along an existing path for the capacity of that path and note that a new transmission facility could reduce congestion and allow that market participant to purchase more electricity, exceeding the capacity of the transmission path for the financial transmission right, at a lower price. While the extent of production cost savings from any Long-Term Regional Transmission Facility or portfolio of such Facilities may vary among representative transmission providers, and transmission providers may propose on compliance to consider the effects of financial transmission rights on Final Rule Benefit 3, we decline to prospectively determine how any load-serving entity may or may not benefit from a reduction in regional production costs, including whether the

[1111] In light of this clarification, we continue to conclude that Order No. 1920 is a lawful exercise of the Commission's statutory authority and does not intrude into areas of reserved state jurisdiction. *See supra* Statutory Authority section; SERTP Sponsors Rehearing Request at 18-19 nn.46 & 48, 43 (Issue Statement 15) (citations omitted). To the extent that transmission providers propose a different evaluation of production cost savings than reflected in state-regulated integrated resource plans, they will be doing so in the context of Order No. 1920's regulation of Commission-jurisdictional transmission planning processes.

degree to which a particular load-serving entity may have hedged against congestion would affect such benefits.

### 2. Measurement and Use of Other Benefits

#### a. Order No. 1920 Requirements

411. In Order No. 1920, the Commission declined to require transmission providers to measure and use the remaining five benefits described in the NOPR in Long-Term Regional Transmission Planning (i.e., mitigation of weather and load uncertainty, generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity), but permitted transmission providers to measure and use additional benefits beyond the set of seven required benefits (other benefits), including on a transmission facility or plan-specific basis, subject to the requirement that they do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.[1112] The Commission stated that, in particular, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected to address Long-Term Transmission Needs, which necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any

[1112] Order No. 1920, 187 FERC ¶ 61,068 at PP 821-822.

beyond the seven benefits that the Commission required transmission providers to include in their OATTs.[1113]

**b. Requests for Rehearing and Clarification**

412. PIOs assert that the Commission erred by not requiring transmission providers to measure and use the five additional benefits identified in the NOPR.[1114] PIOs assert that the Commission ignores its own evidence in the NOPR that the five additional proposed benefits have a proven track record, can be discretely measured, and are unlikely to cause duplication.[1115]

413. TAPS asserts that Order No. 1920's lack of a requirement for transmission providers to fully explain and justify additional benefits used to evaluate Long-Term Regional Transmission Facilities is an unjustified departure from the NOPR and inconsistent with the final rule's directive requiring transmission providers to describe how they will measure each of the seven required benefits on compliance. TAPS states that the final rule invites transmission providers to supplement Order No. 1920's required benefits, seemingly abandoning concerns about double-counting. TAPS further argues that the flexibility regarding additional benefits also provides an opportunity to selectively apply additional benefits on a transmission facility or plant-specific basis,

[1113] *Id.* P 737.

[1114] PIOs Rehearing Request at 26-27.

[1115] *Id.* at 27 (citing NOPR, 179 FERC ¶ 61,028 at PP 208-209, 213-225).

inviting discrimination.[1116] TAPS also asserts that it is unclear whether the final rule's requirements for transmission providers to be "open and transparent" applies to the process of deciding whether to use and how to measure additional benefits or to the implementation of the additional benefits for specific projects. TAPS contends that it should apply to both.[1117]

### c. Commission Determination

414. We are not persuaded by PIOs' rehearing request concerning the Commission's decision in Order No. 1920 to not require the measurement and use of benefits other than the seven required benefits, such as the five additional benefits identified by the Commission in the NOPR. The Commission determined that measurement and use of the set of seven required benefits constituted the just and reasonable replacement rate. Furthermore, the Commission explained its reasoning in Order No. 1920 for only requiring the measurement and use of seven required benefits and not other benefits, including recognizing commenters' concerns about duplication of certain benefits and the difficulty of measuring certain benefits.[1118] The Commission also explained that the list of seven required benefits only requires transmission providers to measure and use seven

[1116] TAPS Rehearing Request at 12-13.

[1117] *Id.* at 11.

[1118] Order No. 1920, 187 FERC ¶ 61,068 at P 724.

specific benefits that have a proven track record, can be discretely measured, and are unlikely to cause duplication.[1119]

415. With respect to TAPS' concerns regarding a lack of a requirement for transmission providers to explain and justify other benefits on compliance, we believe that the approach in the final rule is reasonable because it provides transmission providers with greater flexibility to consider potential additional benefits of Long-Term Regional Transmission Facilities beyond the seven required benefits. We further find that, by providing transparency, the requirements of the final rule are sufficient to avoid undue discrimination. Specifically, Order No. 1920 requires transmission providers that measure and use any other benefits beyond the set of seven required benefits to do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.[1120] Moreover, the Commission stated that the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected to address Long-Term Transmission Needs, which necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits

[1119] *Id.* P 724.

[1120] *Id.* PP 821-822.

that the Commission required transmission providers to include in their OATTs.[1121] Such transparency will limit the opportunities for transmission providers to measure and use in Long-Term Regional Transmission Planning any benefits in addition to the required benefits in an unduly discriminatory manner.

416. We therefore grant TAPS' request for clarification that the final rule's requirements for transmission providers to be "open and transparent" applies to the process of deciding whether to use and how to measure other benefits in addition to the required benefits as well as to the implementation of other benefits for specific Long-Term Regional Transmission Facilities, as discussed above.

### 3. Identification, Measurement, and Evaluation of Benefits

#### a. Order No. 1920 Requirements

417. In Order No. 1920, the Commission required transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the set of seven required benefits, sufficient only to enable stakeholders to understand the manner by which transmission providers will measure these benefits.[1122] Order No. 1920 provided flexibility to transmission planners to specify the method for measuring each of the seven required benefits,[1123] as well as discretion to measure and use additional benefits that go beyond the set of seven required benefits,

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[1121] *Id.* P 737.

[1122] *Id.* PP 837, 840.

[1123] *Id.* P 839.

subject to the requirement that they do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.[1124]

### b. Requests for Rehearing and Clarification

418. SERTP Sponsors request that the Commission clarify that it did not intend for transmission providers to engage in generation or resource planning as part of the Long-Term Regional Transmission Planning process, as doing so would violate FPA section 201 because it would intrude upon state-jurisdictional resource decisions. SERTP Sponsors also request clarification that it is reasonable for transmission providers to establish protocols by which they can rely, to the extent available, on resource planners and load-serving entities for data in support of generation-based benefits.[1125]

### c. Commission Determination

419. In response to SERTP Sponsors' request, we clarify that Order No. 1920 does not require transmission providers to engage in generation or resource planning as part of Long-Term Regional Transmission Planning. The requirement for transmission providers to measure and use the set of seven required benefits in Long-Term Regional Transmission Planning is necessary for transmission providers to consider a sufficiently broad range of benefits when evaluating and determining whether to select a Long-Term Regional Transmission Facility as the more efficient or cost-effective regional

[1124] *Id.* P 822.

[1125] SERTP Sponsors Rehearing Request at 17-18.

transmission solution to Long-Term Transmission Needs and for purposes of conducting Long-Term Regional Transmission Planning, and not as a basis to cause transmission providers to engage in resource planning.[1126]

420. Further, as requested by SERTP Sponsors, we clarify that Order No. 1920 does not prohibit transmission providers from proposing to establish protocols by which they can rely, to the extent available, on resource planners and load-serving entities for generation-based data and information in satisfying the requirement to measure the benefits of Long-Term Regional Transmission Facilities. In Order No. 1920, the Commission provided flexibility to transmission providers to specify the method for measuring each of the seven required benefits and did not mandate any specific method for measuring those seven benefits. Order No. 1920 also provided the flexibility for transmission providers to establish protocols to obtain data, to the extent available, from resource planners and load-serving entities to measure the benefits of specific Long-Term Regional Transmission Facilities. However, we re-emphasize that, whether the transmission providers themselves measure the benefits of Long-Term Regional Transmission Facilities, or instead establish protocols by which they can rely on resource planners or load-serving entities for generation-based data and information to measure the benefits, the general description in the OATT of the method that the transmission provider uses to

[1126] In light of this clarification, we need not reach SERTP Sponsors' alternative argument that, absent this clarification, Order No. 1920 would raise concerns that the Commission has exceeded its jurisdiction. *See id.* at 19 n.48, 43 (Issue Statement 15) (citations omitted).

measure each of the required benefits must be sufficient to enable stakeholders to understand the manner by which transmission providers will measure those benefits, as noted in Order No. 1920.[1127]

#### 4. Benefits Horizon

##### a. Order No. 1920 Requirements

421. In Order No. 1920, the Commission required transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, and the Commission stated that this minimum 20-year benefit horizon must be used both for the evaluation and selection of Long-Term Regional Transmission Facilities.[1128] In addition, in Order No. 1920, the Commission stated that, while transmission providers may discount the benefits calculated for purposes of determining a present value of those benefits, they may not further discount those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits.[1129]

422. In prohibiting transmission providers from discounting benefits to reflect uncertainty over the 20-year benefits horizon, the Commission stated that Order No. 1920

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[1127] Order No. 1920, 187 FERC ¶ 61,068 at P 840.

[1128] *Id.* P 859.

[1129] *Id.* P 865.

affords transmission providers with considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning through the process to develop Long-Term Scenarios.[1130] In addition, the Commission noted that transmission providers have the flexibility to evaluate Long-Term Regional Transmission Facilities and their measured benefits across the different Long-Term Scenarios and sensitivities in a manner that addresses the inherent uncertainty in Long-Term Regional Transmission Planning, for example, through the use of a least-regrets or a weighted-benefits approach.[1131] As a result, the Commission determined that transmission providers have considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning, including the calculation of benefits under different future scenarios, and that transmission providers did not need additional flexibility that would be realized by discounting benefits over time specifically due to future uncertainty.[1132]

**b. Requests for Rehearing and Clarification**

423. SERTP Sponsors request rehearing of the Commission's determination in Order No. 1920 to prohibit discounting of the measured benefits of Long-Term Regional Transmission Facilities based on uncertainty over the minimum 20-year benefit horizon. According to SERTP Sponsors, by requiring a 20-year benefits estimation without permitting discounting to reflect uncertainty, while also allowing a weighted-benefits

[1130] *Id.* PP 861, 865.

[1131] *Id.* P 862.

[1132] *Id.* PP 862, 865.

approach to account for uncertainty, Order No. 1920's requirement and authorization are unclear and contradictory, and therefore arbitrary and capricious.[1133] Similarly, Dominion states that the Commission must provide transmission providers with the flexibility to discount the measured benefits to reflect uncertainty over the minimum 20-year horizon for purposes of selection and evaluation of projects.[1134]

**c. Commission Determination**

424. We sustain the finding in Order No. 1920 that, while transmission providers may discount the value of the benefits calculated for purposes of determining the present value of those benefits, they may not further reduce the estimates of those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits. We disagree with SERTP Sponsors that Order No. 1920 is contradictory in allowing the use of a weighted-benefits approach for evaluating Long-Term Regional Transmission Facilities while also prohibiting the reduction in estimates of measured benefits based on uncertainty over the minimum 20-year horizon. These two techniques are not the same, and allowing one but prohibiting the other is not contradictory. Permitting transmission providers to use a weighted-benefits approach for Long-Term Regional Transmission Facilities allows transmission providers to measure the estimated total benefits that a

[1133] SERTP Sponsors Rehearing Request at 19-20, 43 (Issue Statement 16) (citations omitted); *see also id.* at 43 (Issue Statement 15) (citations omitted) (asserting that failure to grant clarification of the issues in Section II.C.3 of SERTP Sponsors' argument would result in the Commission intruding on state-jurisdictional resource decisions).

[1134] Dominion Rehearing Request at 21-25.

particular Long-Term Regional Transmission Facility may provide across a range of Long-Term Scenarios, each with a different probability of occurrence.[1135] This method can help account for uncertainty in the total benefits that a Long-Term Regional Transmission Facility may provide and help to balance an over-reliance on any particular Long-Term Scenario. While we understand that applying a probability to a Long-Term Scenario, and its resulting benefits, may reduce the benefits measured for that particular Long-Term Scenario, when aggregated, the probability-weighted benefits measured across all Long-Term Scenarios results in a representative estimate of the total benefits of the Long-Term Regional Transmission Facility as a whole while also accounting for uncertainty regarding the likelihood of different Long-Term Scenarios being realized.

425. On the other hand, we continue to find that allowing transmission providers to reduce the estimates of certain benefits based only on the relative certainty over the 20-year benefits horizon is unnecessary given other flexibilities provided to transmission providers to manage uncertainty in planning over a minimum of 20 years, for the reasons discussed in Order No. 1920.[1136] For example, in addition to the use of a weighted-

[1135] Under a weighted-benefits approach, transmission providers that use three Long-Term Scenarios with expected likelihoods of, for example, 30%, 30%, and 40%, would attribute these expected likelihoods to the benefits that the transmission provider measures under each Long-Term Scenario. The total estimated benefits of the Long-Term Regional Transmission Facility would then be calculated by summing the probability-adjusted benefits across these three Long-Term Scenarios (i.e., the sum of the measured benefits in the first Long-Term Scenario multiplied by its 30% probability, plus the second Long-Term Scenario's benefits multiplied by 30%, plus the third Long-Term Scenario's benefits multiplied by 40%).

[1136] Order No. 1920, 187 FERC ¶ 61,068 at P 865.

benefits approach, transmission providers have flexibility in how they account for the factors that go into Long-Term Scenario development once, as discussed elsewhere in this rule, transmission providers consult with Relevant State Entities and their authorized representatives as to how to account for factors related to state policy when determining the assumptions that will be used in the development of Long-Term Scenarios, as well as in determining *how* to account for such a state-related factor when developing Long-Term Scenarios when such state input is available.[1137].

426. As a result, we continue to believe that prohibiting the discounting of benefits based on relative certainty over the 20-year benefits horizon is reasonable and strikes an appropriate balance between preventing an excessive undercounting of benefits and allowing transmission providers to account for uncertainty in measuring benefits of Long-Term Regional Transmission Facilities across Long-Term Scenarios. For these reasons, we also disagree with Dominion that transmission providers must be afforded the flexibility to discount benefits based on the uncertainty in planning over a minimum 20-year horizon.

427. SERTP Sponsors do not explain how, in the absence of their requested clarification regarding discounting the benefits of Long-Term Regional Transmission Facilities, Order No. 1920 would "intrude[ ] upon state-jurisdictional resource decisions."[1138] Regardless, we would be unpersuaded by this argument on its merits

[1137] *See supra* Long-Term Scenarios Requirements, Stakeholder Process and Transparency section.

[1138] SERTP Sponsors Rehearing Request at 43 (Issue Statement 15) (citations

because, as described above, Order No. 1920 falls comfortably within the Commission's jurisdiction to regulate practices directly affecting Commission-jurisdictional rates.[1139] The manner in which benefits of Long-Term Regional Transmission Facilities are assessed is such a Commission-jurisdictional practice.

### 5. Evaluation of the Benefits of Portfolios of Transmission Facilities

#### a. Order No. 1920 Requirements

428. In Order No. 1920, the Commission allowed, but not did not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities. Further, the Commission required transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities to include provisions in their OATTs regarding their use of the portfolio approach.[1140]

#### b. Requests for Rehearing and Clarification

429. PIOs request rehearing of the Commission's decision in Order No. 1920 to not require transmission providers to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1141] PIOs state that the record in this docket

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omitted); *id.* at 37-41 (generic argument that failure to grant certain clarifications intrudes on state jurisdiction or may implicate the major questions doctrine, without discussion of discounting benefits).

[1139] *See supra* Statutory Authority section.

[1140] Order No. 1920, 187 FERC ¶ 61,068 at P 889.

[1141] PIOs Rehearing Request at 47 (citations omitted).

includes widespread commenter support and substantial evidence, ranging from expert reports to examples of existing processes, demonstrating the benefits of using a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1142] PIOs argue that by allowing transmission providers to continue to evaluate the benefits of Long-Term Regional Transmission Facilities on a facility-by-facility basis, the Commission undermines Order No. 1920's central purpose of requiring planning for system-wide transmission needs on a comprehensive and regional basis and leaves in place unjust and unreasonable rates.[1143] PIOs state that the Commission could provide transmission providers with flexibility while meeting the goals of Order No. 1920 by establishing a rebuttable presumption that Long-Term Regional Transmission Facilities be assessed on a portfolio basis, which transmission providers could overcome by demonstrating that the portfolio approach is inapplicable in a particular instance.[1144]

430. Undersigned States[1145] and Designated Retail Regulators request rehearing of Order No. 1920's decision to allow transmission providers to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1146]

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[1142] *Id.* at 44-46.

[1143] *Id.* at 47.

[1144] *Id.* 47-48 (citing US DOE NOPR Initial Comments at 34-35).

[1145] Undersigned States note that the state of North Dakota does not join in the portion of Undersigned States' request for rehearing that addresses the final rule's determinations concerning the portfolio approach. Undersigned States Rehearing Request at 29 n.19.

[1146] Designated Retail Regulators Rehearing Request at 33-34; Undersigned States

Designated Retail Regulators and Undersigned States opine that the Commission should prohibit transmission providers from using the portfolio approach because, by allowing the bundling of economic and uneconomic facilities such that all facilities in a portfolio appear economic on a collective basis, the portfolio approach spreads uneconomic project costs to non-beneficiaries.[1147] Designated Retail Regulators and Undersigned States further argue that the portfolio approach results in the unjust and unreasonable recovery of costs exceeding benefits and that every facility approved for construction should be economic and meet the required benefits-to-cost ratio on a stand-alone basis.[1148]

### c. Commission Determination

431. We are unpersuaded by PIOs', Undersigned States', and Designated Retail Regulators' requests for rehearing of the Commission's decision to allow, but not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities. We disagree with PIOs' arguments that the Commission's decision not to require transmission providers to use a portfolio approach undermines the goals or purpose of Order No. 1920 or leaves unjust and unreasonable rates in place.[1149] We continue to find

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Rehearing Request at 29-30.

[1147] Designated Retail Regulators Rehearing Request at 34; Undersigned States Rehearing Request at 30.

[1148] Designated Retail Regulators Rehearing Request at 34; Undersigned States Rehearing Request at 30.

[1149] *See* PIOs Rehearing Request at 47.

that the advantages of a portfolio approach to evaluating benefits must be balanced against other considerations and that it is appropriate to provide transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach, subject to the requirement that transmission providers that propose to use a portfolio approach include provisions in their OATTs regarding their use of the portfolio approach.[1150]

432. Specifically, we find that the advantages of a portfolio approach to evaluating benefits—including administrative efficiencies related to economies of scale and a more stable or even distribution of benefits, which is likely to facilitate agreement on regional cost allocation—must be weighed against the fact that a portfolio approach may not be appropriate in all instances. For example, a facility-by-facility approach may be more appropriate if Long-Term Scenarios reveal the same or nearly identical constraints in discrete and isolated areas of the transmission system where system upgrades would be beneficial. We find that transmission providers are in the best position to determine in any given circumstance whether a portfolio or facility-by-facility approach to evaluate the benefits of Long-Term Regional Transmission Facilities is more appropriate.

[1150] Order No. 1920, 187 FERC ¶ 61,068 at PP 889-890. Order No. 1920 requires transmission providers that propose to use a portfolio approach to indicate in their proposed OATTs that they will use a portfolio approach. However, Order No. 1920 does not require transmission providers to indicate whether they will use a portfolio approach for all Long-Term Regional Transmission Facilities or only in certain specified instances, nor to describe how they will analyze the benefits of Long-Term Regional Transmission Facilities under a portfolio approach, as such requirements could impede transmission provider consideration and development of portfolio approaches. *Id.* P 889.

Therefore, we sustain the determination in Order No. 1920 to provide transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach, subject to the requirement that transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities include provisions in their OATTs regarding their use of the portfolio approach.

433. We are also unpersuaded by Designated Retail Regulators' and Undersigned States' requests that the Commission prohibit transmission providers from using a portfolio approach to evaluate the benefits of Long-Term Regional Transmission Facilities. We note that the Commission has previously accepted the use of the portfolio approach to the evaluation of transmission facilities.[1151] In response to Undersigned States' claim that the portfolio approach allocates uneconomic project costs to non-beneficiaries, we note that the measurement and use of the benefits of Long-Term Regional Transmission Facilities, whether on a portfolio or facility-by-facility basis, is a requirement for the evaluation of Long-Term Regional Transmission Facilities for the purposes of potential selection. Order No. 1920 provides transmission providers with flexibility as to the consideration of benefits in their cost allocation methods for Long-Term Regional Transmission Facilities, subject to the requirement that transmission

[1151] *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221, at PP 221-222 (2010), *order on reh'g and compliance filing*, 137 FERC ¶ 61,074 (2011), *aff'd in part, dismissed in part and remanded in part sub nom. Ill. Com. Comm'n v. FERC*, 721 F.3d 764, 780 (7th Cir. 2013).

providers demonstrate that such cost allocation methods allocate costs in a manner that is at least roughly commensurate with estimated benefits.[1152] Thus, Designated Retail Regulators' and Undersigned States' arguments that the portfolio approach to evaluation of benefits will result in the allocation of costs for uneconomic facilities are unfounded.

### D. Evaluation and Selection of Long-Term Regional Transmission Facilities

#### 1. Minimum Requirements

##### a. Order No. 1920 Requirements

434. In Order No. 1920, the Commission required transmission providers in each transmission planning region to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.[1153] The Commission further held that the transmission developer of a selected Long-Term Regional Transmission Facility will be eligible to use the applicable cost allocation method for that Long-Term Regional Transmission Facility.

435. The Commission provided flexibility to transmission providers to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria,[1154] provided that they (1) are transparent and not unduly

[1152] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1478, 1506 (citing *ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564).

[1153] Order No. 1920, 187 FERC ¶ 61,068 at P 911.

[1154] *Id.* P 924.

discriminatory;[1155] (2) aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs;[1156] and (3) seek to maximize benefits accounting for costs over time without over-building transmission facilities.[1157]

436. As to the requirement that transmission providers' evaluation processes, including selection criteria, are transparent and not unduly discriminatory, the Commission explained that transmission providers' evaluation of Long-Term Regional Transmission Facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) was selected or not selected.[1158] The Commission also explained that this determination must include the estimated costs and measured benefits of each Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) that transmission providers evaluated in the Long-Term Regional Transmission Planning process, regardless of whether the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[1159] The Commission further explained that, where transmission providers employ a portfolio

[1155] *Id.* P 954.

[1156] *Id.* P 955.

[1157] *Id.* P 964.

[1158] *Id.* P 954

[1159] *Id.* PP 954, 966.

approach to evaluating and selecting Long-Term Regional Transmission Facilities, transmission providers may provide the measured benefits included in this determination on an aggregate basis.[1160]

437. As to the requirement that transmission providers' evaluation processes, including selection criteria, must aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs, the Commission explained that evaluation processes must: (1) identify one or more Long-Term Regional Transmission Facilities (or portfolio of Long-Term Regional Transmission Facilities) that address the Long-Term Transmission Needs that transmission providers identify in Long-Term Regional Transmission Planning; (2) estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities that are identified or proposed for potential selection; (3) designate a point in the evaluation process that is no later than three years following the beginning of the Long-Term Regional Transmission Planning cycle at which transmission providers will determine to select or not to select identified or proposed Long-Term Regional Transmission Facilities; and (4) culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) was selected or not selected.[1161] The Commission also provided transmission providers with flexibility to

[1160] *Id.* P 966 n.2121.

[1161] *Id.* P 955. As to the identification of Long-Term Regional Transmission Facilities, Order No. 1920 requires, consistent with Order Nos. 890 and 1000, that

determine how they will evaluate whether Long-Term Regional Transmission Facilities more efficiently or cost-effectively address Long-Term Transmission Needs, including by using benefit-cost ratios, assessing their net benefits, and/or using some other method. Consistent with cost allocation principle (3), however, the Commission prohibited transmission providers from imposing as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[1162]

438. Finally, as to the requirement that transmission providers' evaluation processes, including selection criteria, must seek to maximize benefits accounting for costs over time without over-building transmission facilities, the Commission stated that transmission providers could adopt evaluation processes and selection criteria that would allow transmission providers to make selection decisions while addressing the uncertainty inherent in Long-Term Regional Transmission Planning. For example, transmission providers could include features that minimize the future risk of developing a previously selected Long-Term Regional Transmission Facility that is not the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs, such as by using a least-regrets or weighted-benefits approaches.[1163] The Commission explained

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nonincumbent transmission developers be able to propose transmission facilities in Long-Term Regional Transmission Planning, and that therefore transmission providers make clear in their OATTs the point in the Long-Term Regional Transmission Planning evaluation process at which they will accept Long-Term Regional Transmission Facility proposals from stakeholders, including nonincumbent transmission developers. *Id.*

[1162] *Id.* P 958 (citation omitted).

[1163] *Id.* P 967. The Commission explained that, under a least-regrets approach, transmission providers would select Long-Term Regional Transmission Facilities if those

that, consistent with this requirement, transmission providers may not disregard benefits that they are required to use and measure, and may not do so even where those benefits only are measured under certain transmission system conditions.[1164] The Commission further explained that transmission providers may not adopt an approach under which a Long-Term Regional Transmission Facility would be required to meet the selection criteria in every Long-Term Scenario and sensitivity.[1165]

**b. Requests for Rehearing and Clarification**

439. NRECA argues that the Commission violated the APA's notice-and-comment requirements because the NOPR did not propose the "prescriptive" requirements set forth in Order No. 1920 related to the evaluation of Long-Term Regional Transmission Facilities.[1166] These include the requirement that transmission providers identify Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs, estimate the costs and measure the benefits of such facilities, and designate a point in the evaluation process, no later than three years from the date when the Long-Term Regional

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facilities are net beneficial in more than one Long-Term Scenario and sensitivity analysis even if other transmission facilities have a higher benefit-cost ratio or provide more net benefits in a single Long-Term Scenario or particular sensitivity. Under a weighted-benefits approach, transmission providers would select a Long-Term Regional Transmission Facility based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario or sensitivity thereof that is studied. *Id.*

[1164] *Id.* P 965.

[1165] *Id.* P 968.

[1166] NRECA Rehearing Request at 14.

Transmission Planning cycle begins, at which time the transmission provider will determine whether to select or not select those identified Long-Term Regional Transmission Facilities.[1167]

440. NRECA also requests that the Commission grant rehearing and require that transmission providers' selection criteria ensure the selection of Long-Term Regional Transmission Facilities that meet the reasonable needs of load-serving entities, which NRECA argues that they must do under FPA section 217(b)(4). Further, NRECA contends that FPA section 217(b)(4) requires that selection criteria enable load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[1168]

441. PIOs request rehearing of the Commission's determination to allow transmission providers to adopt benefit-cost ratios as high as 1.25-to-1.00 and request that the Commission require benefit-cost ratios no higher than 1.00-to-1.00. PIOs contend that a 1.25-to-1.00 benefit-cost ratio does not work in the context of scenario-based planning using a portfolio approach because some Long-Term Regional Transmission Facilities

[1167] NRECA Rehearing Request at 14-15 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 381, 955).

[1168] *See* NRECA Rehearing Request at 39-43. As with its arguments related to the discretion provided under Order No. 1920 for transmission providers to determine that factors in Factor Category Three may not affect Long-Term Transmission Needs, NRECA also argues with respect to selection criteria that the Commission should revisit its conclusion that *South Carolina Public Service Authority v. FERC* remains good law on the meaning of FPA section 217(b)(4). *Id.* at 40-41.

may, in isolation, be below 1.25-to-1.00 despite raising the value of a portfolio of Long-Term Regional Transmission Facilities above such a threshold.[1169] PIOs also argue that the measured benefits of certain Long-Term Regional Transmission Facilities may depend on the Long-Term Scenario or sensitivity within which benefits are measured, and that it does not make sense to apply a benefit-cost ratio threshold to Long-Term Regional Transmission Facilities whose benefits are not fixed.[1170]

442. ITC requests rehearing of the Commission's decision to allow, but not to require, transmission providers to adopt least-regrets approaches to selecting Long-Term Regional Transmission Facilities. ITC argues that, given other requirements in Order No. 1920, a least-regrets approach would hedge against the inherent uncertainty of Long-Term Regional Transmission Planning by ensuring that selected Long-Term Regional Transmission Facilities provide robust benefits over a wide variety of future system conditions.[1171]

443. Dominion states that Order No. 1920 is clear that transmission providers "*can* compare calculated benefits [of Long-Term Regional Transmission Facilities] to costs for purposes of project evaluation and selection."[1172] Dominion requests that the

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[1169] PIOs Rehearing Request at 48-49 (citing PIOs NOPR Initial Comments, ex. A at 12-17).

[1170] *Id.* at 48-49.

[1171] ITC Rehearing Request at 11-12.

[1172] Dominion Rehearing Request at 25 (emphasis added) (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 955, 964-965).

Commission clarify that transmission providers may weigh measured benefits against "other factors" and that transmission providers may propose "what factors will be considered," provided that transmission providers' selection criteria are "sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected."[1173] Dominion further requests that the Commission clarify what different "costs" transmission providers can consider and weigh against measured benefits beyond the direct costs of the construction and operation of the specific Long-Term Regional Transmission Facility. By way of example, Dominion explains that some Long-Term Regional Transmission Facilities may allow for the delivery of more generation to an area of high load demand, while also creating reliability issues on another transmission facility. If upgrades to that transmission facility are made in response to those reliability issues, Dominion requests clarification that transmission providers can consider the costs of those upgrades to be a "cost" of the Long-Term Regional Transmission Facility.[1174]

444. Finally, TAPS requests rehearing of the Commission's decision not to require that transmission providers calculate and provide to the transmission planning region's stakeholders TAPS's proposed "affordability metrics." TAPS explains that this proposed requirement would include the projected incremental transmission rate impact that each

[1173] *Id.* at 25-26 (punctuation omitted) (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 737).

[1174] *Id.*

Long-Term Regional Transmission Facility would provide, if selected, and the projected total transmission rate that transmission customers would pay if all selected Long-Term Regional Transmission Facilities are placed in service. TAPS explains that transmission providers should make these calculations on the basis of the default *ex ante* Long-Term Regional Transmission Cost Allocation Method (in the absence of any state agreement), covering a period extending at least 20 years after the Long-Term Regional Transmission Facility is expected to be in commercial operation, and would be required to share their assumptions and calculations. TAPS explains that transmission providers should also provide a process for stakeholders to submit questions and verify information. TAPS argues that the Commission's rejection of affordability metrics was "conclusory" and did not satisfy the Commission's obligation to engage with comments.[1175]

### c. Commission Determination

445. We disagree with the rehearing arguments submitted by NRECA. First, the Commission did not violate the APA's notice-and-comment requirements when it modified the NOPR proposal to be more "prescriptive"[1176] by requiring that the evaluation and selection processes that transmission providers propose must: (1) identify Long-Term Regional Transmission Facilities that address the Long-Term Transmission

[1175] TAPS Rehearing Request at 20-22 ("[T]he 'Commission cannot satisfy its mandate to engage with parties' comments by relying on conclusory statements that dismissed a party's concerns without providing reasoned analysis.'" (internal quotation and alteration omitted) (quoting *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th 795, 804 (D.C. Cir. 2021)).

[1176] NRECA Rehearing Request at 14.

Needs they have identified;(2) estimate the costs and measure the benefits of such facilities; and (3) designate a point in the evaluation process when the transmission provider will determine whether to select or not select those facilities. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a "logical outgrowth" of the proposed rule.[1177]

446. The final rule is a logical outgrowth of the NOPR in this regard. The Commission described Long-Term Regional Transmission Planning in the NOPR as regional transmission planning that: (1) identifies transmission needs driven by changes in the resource mix and demand; (2) evaluates transmission facilities that meet such needs; and (3) identifies and evaluates such transmission facilities for potential selection to meet those needs.[1178] The NOPR also proposed to require that transmission providers' selection criteria "aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand."[1179] In

[1177] *Long Island Care at Home, Ltd. v. Coke*, 551 U.S. 158, 174-75 (2007) (*Long Island Care*). *See also Am. Paper Inst. v. EPA*, 660 F.2d 954, 959 n.13 (4th Cir. 1981) ("An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.") (emphasis added).

[1178] *See* NOPR, 179 FERC ¶ 61,028 at P 68. Order No. 1920 adopted a definition of Long-Term Transmission Needs that includes transmission needs driven by changes in the resource mix and demand. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 299 (describing the drivers of Long-Term Transmission Needs as including changes in the resource mix and changes in demand).

[1179] NOPR, 179 FERC ¶ 61,028 at P 245.

Order No. 1920, the Commission modified the NOPR proposal "to provide additional clarity as to how transmission providers' evaluation processes must aim to ensure the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs."[1180] The Commission then set forth procedural requirements that require transmission providers to meet the NOPR definition of Long-Term Regional Transmission Planning by: (1) identifying Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs; (2) estimating the costs and measuring the benefits of such facilities as part of the evaluation process; and (3) designating a point when transmission providers will make a decision to select or not select such facilities.[1181] These additional procedural clarifications satisfy the logical outgrowth test because the requirements in Order No. 1920 achieve the same ends using very similar means to those proposed in the NOPR. Accordingly, we find that the evaluation requirements follow logically from the NOPR and that the NOPR adequately framed the subjects for discussion such that a reasonable member of the regulated class would anticipate the general aspects of the final rule.[1182]

447. Second, we disagree with NRECA's rehearing argument that, in order to satisfy FPA section 217(b)(4), the Commission must impose a specific requirement that

[1180] Order No. 1920, 187 FERC ¶ 61,068 at P 955.

[1181] *Id.*

[1182] *Conn. Light & Power Co. v. Nuclear Regul. Comm'n*, 673 F.2d 525, 533 (D.C. Cir. 1982); *Telesat Canada v. FCC*, 999 F.3d 707, 713-14 (D.C. Cir. 2021).

transmission providers' selection criteria ensure the selection of Long-Term Regional Transmission Facilities that meet the reasonable needs of load-serving entities and enable load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs. Fulfilling the requirements of FPA section 217(b)(4) does not require that the Commission impose the selection criterion that NRECA prefers, and we find that the criteria that the Commission required represent a superior and, in any case, just and reasonable and not unduly discriminatory or preferential approach to this issue. Moreover, the Commission explained in Order No. 1920 that, "[t]hrough the requirements of this final rule, we seek to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations and facilitate the planning of a reliable grid, consistent with FPA section 217(b)(4)."[1183]

448. We further disagree with the rehearing arguments submitted by PIOs, and we sustain the Commission's holding that, consistent with Order No. 1000 regional cost allocation principle (3), transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[1184] We do not agree with

[1183] Order No. 1920, 187 FERC ¶ 61,068 at P 1001. *See also id.* PP 283, 447 (discussing Commission's obligations under FPA section 217(b)(4) and its application to Order No. 1920). We also reject NRECA's argument that the Commission should revisit its conclusion that *South Carolina Public Service Authority v. FERC* remains good law for the same reasons provided in the Other Specific Required Categories of Factors section above.

[1184] *Id.* P 958.

PIOs that this holding is inconsistent with the use of a portfolio approach to selecting Long-Term Regional Transmission Facilities. While PIOs are correct that the benefits of Long-Term Regional Transmission Facilities may depend on the Long-Term Scenario or sensitivity in which they are measured, Order No. 1920 does not require transmission providers to apply benefit-cost ratios within specific Long-Term Scenarios or sensitivities.[1185] Further, the fact that the measured benefits of Long-Term Regional Transmission Facilities may differ among the Long-Term Scenarios or sensitivities studied does not render the use of benefit-cost ratios incompatible with Long-Term Regional Transmission Planning. In fact, the least-regrets and weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities described in Order No. 1920 are examples of how transmission providers may make selection decisions notwithstanding the fact that the measured benefits of Long-Term Regional Transmission Facilities may differ depending on the Long-Term Scenario or sensitivity in which they are measured.[1186]

449. We also disagree with the rehearing arguments advanced by ITC. While we agree with ITC that a least-regrets approach to selecting Long-Term Regional Transmission

[1185] *See id.* P 956 (requiring transmission providers to make transparent the methods that they used to analyze each individual Long-Term Scenario and the sensitivity or sensitivities applied to each scenario to determine the Long-Term Transmission Needs that exist in the transmission planning region, the Long-Term Regional Transmission Facilities that would resolve those needs, and the benefits of those Long-Term Regional Transmission Facilities for purposes of selection).

[1186] *Id.* P 967. *See infra* Benefits Horizon section.

Facilities may allow transmission providers to address the inherent uncertainty of Long-Term Regional Transmission Planning, we disagree that this is the only such approach,[1187] and therefore we sustain the Commission's holding that transmission providers are not required to use this approach.[1188] Generally, the Commission attempted in Order No. 1920 to ensure that transmission providers have the flexibility that they need to develop evaluation processes, including selection criteria, that meet the minimum requirements set forth in Order No. 1920, and we are not persuaded by PIOs or ITC to limit that flexibility here, either by reducing the maximum benefit-cost ratio that transmission providers may propose to use as a selection criterion in Long-Term Regional Transmission Planning or by requiring a particular selection approach.

450. We grant clarification, in part, to Dominion. As an initial matter, we clarify that transmission providers' evaluation processes must—not can—compare the measured benefits of Long-Term Regional Transmission Facilities against their estimated costs.[1189]

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[1187] *See id.* P 967 (describing least-regrets *and* weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities as potential methods to manage uncertainty).

[1188] *Id.* P 968.

[1189] *See id.* P 955 ("Second, transmission providers' evaluation processes must estimate the costs and measure the benefits of the Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are identified or proposed for potential selection, *in addition* to evaluating the identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities) using any qualitative or other quantitative selection criteria that the transmission providers in a transmission planning region propose to apply." (emphasis added)); *id.* P 964 (requiring transmission providers to propose evaluation processes, including selection criteria, that seek to *maximize benefits accounting for costs* over time without over-building transmission facilities) (emphasis

The purpose of such a comparison is for transmission providers to determine the benefits of Long-Term Regional Transmission Facilities for purposes of applying the transmission provider's selection criteria.[1190] We further clarify that, once a transmission provider makes a selection decision, i.e., for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities), and, if a State Agreement Process is used, once a cost allocation method is agreed upon, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how those estimated costs will be allocated, by zone (i.e., by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of those estimated benefits as imputed to each zone, as such benefits can be reasonably estimated. The increase in transparency from this posting requirement ensures that transmission providers make available information that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected. As to Dominion's request that the Commission clarify what—aside from project costs—transmission providers may compare to measured benefits, we reiterate here that transmission providers may propose qualitative measures in their evaluation processes or qualitative selection criteria,[1191]

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added).

[1190] *See id.* P 956 (holding that transmission providers must make clear the methods they used to analyze the benefits of Long-Term Regional Transmission Facilities for purposes of selection).

[1191] *Id.* P 961.

provided that they meet the minimum requirements set forth in Order No. 1920 with which transmission providers' evaluation processes, including selection criteria, must comply.[1192] We further clarify that, contrary to Dominion's understanding,[1193] transmission providers' evaluation processes must culminate in a *determination*—not selection criteria—that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected.[1194] Finally, we clarify that the Commission generally provides transmission providers with the discretion to use engineering judgment in designing and conducting transmission planning studies, and we therefore decline to address Dominion's hypothetical in the abstract.

451. Finally, we are not persuaded by the arguments raised on rehearing by TAPS regarding its proposed "affordability metrics." We find that the potential benefits of requiring that transmission providers make these metrics available are outweighed by the potential burden on transmission providers, who would need to determine on a customer-by-customer basis the effect on incremental rates of a wide variety of rate design and cost recovery factors in order to produce a meaningful analysis. Therefore, we decline to

[1192] *See id.* PP 954-971.

[1193] *See* Dominion Rehearing Request at 26 ("Dominion Energy understands that the Final Rule gives Transmission Providers an opportunity to propose what factors will be considered so long as the *selection criteria* is 'sufficiently detailed to understand why a particular Long-Term Regional Transmission Facility . . . was selected or not selected.") (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 737) (emphasis added).

[1194] Order No. 1920, 187 FERC ¶ 61,068 at PP 737, 954-955, 966, 1214.

adopt any requirement to calculate and make available the "affordability metrics" as described by TAPS. However, even though we do not require transmission providers to calculate rate impacts, as discussed above, we do require transparency regarding the allocation of costs after Long-Term Transmission Facilities are selected.

### 2. Role of Relevant State Entities

#### a. Order No. 1920 Requirements

452. In Order No. 1920, the Commission required transmission providers in each transmission planning region to consult with and seek support from Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional Transmission Facilities for selection.[1195] The Commission declined to adopt the NOPR proposal to require that transmission providers include in their OATTs a process to coordinate with the transmission planning region's Relevant State Entities in developing selection criteria.[1196] Instead, the Commission required transmission providers to demonstrate on compliance that they made good faith efforts to consult with and seek support from Relevant State Entities in their transmission planning region's footprint when developing the evaluation processes and selection criteria that they propose to include in their OATTs.[1197] The Commission did not require transmission providers to obtain the support

[1195] *Id.* P 994.

[1196] *Id.* P 995.

[1197] *Id.* P 994.

of Relevant State Entities before proposing evaluation processes and selection criteria on compliance.[1198]

### b. Requests for Rehearing and Clarification

453. Several parties request rehearing or clarification of Order No. 1920's requirements related to the role that Relevant State Entities will play in developing the evaluation processes, including selection criteria, that transmission providers will propose.[1199]

454. Designated Retail Regulators claim that the Commission violated the APA's notice-and-comment requirements because the NOPR required that states approve the selection criteria that transmission providers will propose to use in Long-Term Regional Transmission Planning, whereas the Commission did not require transmission providers to obtain their support in Order No. 1920. As such, Designated Retail Regulators conclude that Order No. 1920 is not a logical outgrowth of the NOPR proposal because it is "surprisingly distant" from the NOPR.[1200] Similarly, NRECA argues that Order No. 1920 is not a logical outgrowth of the NOPR because the Commission declined to adopt the NOPR proposal that transmission providers include a formal tariff process for

[1198] *Id.* P 996.

[1199] Arizona Commission Rehearing Request at 16; Designated Retail Regulators Rehearing Request at 48-50; NARUC Rehearing Request at 17-21; NESCOE Rehearing Request at 12; NRECA Rehearing Request at 6, 17-19.

[1200] Designated Retail Regulators Rehearing Request at 48-50 (quoting *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 407 F.3d 1250, 1260 (D.C. Cir. 2005)).

coordinating with Relevant State Entities regarding transmission providers' selection criteria.[1201]

455. Arizona Commission argues that the Commission erred in not requiring transmission providers to obtain the agreement of the State of Arizona as to the evaluation processes, including selection criteria, that transmission providers will propose, and requests rehearing because the Commission did not offer any legitimate legal reason or sufficient justification for not requiring such state approval. Arizona Commission asserts that states alone have the inherent police power to regulate the utilities within their states and that the final rule improperly eliminates the State of Arizona's role with respect to selection criteria.[1202] NARUC requests that the Commission grant rehearing such that transmission providers would be required to include in their compliance filings any selection criteria that are "promulgated and supported" by Relevant State Entities.[1203]

456. Finally, NESCOE requests that the Commission clarify Order No. 1920 to provide guidance as to what constitutes "good faith efforts" on the part of transmission providers as they consult with and seek support from Relevant State Entities. NESCOE requests further clarification that the requirement that transmission providers "consult with" Relevant State Entities means that there is an "unambiguous pathway" for states'

[1201] NRECA Rehearing Request at 6, 17-19.

[1202] *See* Arizona Commission Rehearing Request at 16.

[1203] NARUC Rehearing Request at 17.

feedback to be heard and taken into account. Further, NESCOE observes that "consult with" can mean a range of things, from an offer of a one-hour meeting to preview potential selection criteria to interactive and substantive discussions, and it requests that the Commission confirm that the obligation to consult with Relevant State Entities means something more consequential than the former.[1204]

### c. Commission Determination

457. We disagree with the arguments raised on rehearing by Designated Retail Regulators and NRECA that Order No. 1920 is not a logical outgrowth of the NOPR proposal. In particular, we disagree with Designated Retail Regulators that the NOPR proposed to require that states approve transmission providers' selection criteria.[1205] Instead, the NOPR proposed to require that transmission providers "coordinate" with Relevant State Entities in developing selection criteria, and the Commission explained that this would mean that transmission providers "must consult with and seek support from" Relevant State Entities.[1206] Neither statement can be construed as imposing a requirement that states approve the selection criteria to be proposed by transmission providers on compliance. In any event, the Commission adopted the exact proposal from the NOPR, namely, that transmission providers must consult with and seek support from

[1204] NESCOE Rehearing Request at 12.

[1205] Designated Retail Regulators Rehearing Request at 48-49.

[1206] *See* NOPR, 179 FERC ¶ 61,028 at PP 241, 244.

Relevant State Entities, which was subject to a notice and comment period, as required under the APA.

458. Further, while NRECA is correct that in Order No. 1920, the Commission declined to adopt the NOPR proposal for transmission providers to propose on compliance OATT provisions providing for a "process" to coordinate with Relevant State Entities in developing selection criteria,[1207] this does not mean that Order No. 1920 is not a logical outgrowth of the NOPR proposal in this regard. As the D.C. Circuit has explained, "[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step."[1208] The same is true here. Further, the Commission required that transmission providers demonstrate good faith efforts as they consult with and seek support from Relevant State Entities.[1209] We continue to believe that these requirements are sufficient to ensure that transmission providers benefit from Relevant State Entities' views. Nevertheless, we note that Order No. 1920 does not prohibit transmission providers from adopting additional approaches for coordinating with Relevant State

[1207] NRECA Rehearing Request at 17-18.

[1208] *N.Y. v. EPA*, 413 F.3d 3, 44 (D.C. Cir. 2005) (per curiam) (quoting *Am. Iron & Steel Inst. v. EPA*, 886 F.2d 390, 400 (D.C. Cir. 1989)). *See also Long Island Care*, 551 U.S. at 175 (stating, in the context of rejecting claims that an agency provided legally defective notice because it did not finalize a proposed rule, "[w]e do not understand why such a possibility was not reasonably foreseeable"); *Vanda Pharms., Inc. v. Ctrs. for Medicare & Medicaid Servs.*, 98 F.4th 483, 498 (4th Cir. 2024) (*Vanda Pharms*) (The APA's "notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content").

[1209] Order No. 1920, 187 FERC ¶ 61,068 at P 994.

Entities regarding selection criteria and/or consulting with Relevant State Entities in the selection of particular Long-Term Regional Transmission Facilities, and we encourage transmission providers to do so.[1210]

459. We also disagree with the rehearing arguments of Arizona Commission and NARUC. Arizona Commission incorrectly claims that the Commission did not offer any "legitimate legal or sufficient justification" for not requiring state approval of evaluation processes.[1211] As the Commission explained, it is transmission providers who must propose on compliance an evaluation process and selection criteria that comply with the requirements of Order No. 1920, because Long-Term Regional Transmission Planning is the tariff obligation of each transmission provider.[1212] As the Commission further explained, achieving consensus may not be possible in every instance, and transmission providers nevertheless must submit compliance filings consistent with Order No. 1920

[1210] *Id.* PP 994, 996. We reiterate, however, that transmission providers may not include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. *Id.* P 962. Doing so would deny transmission providers the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs, and therefore may lead to failing to address the deficiencies in the Commission's existing regional transmission planning requirements identified in Order No. 1920. *Id.* P 914.

[1211] *See* Arizona Commission Rehearing Request at 16.

[1212] Order No. 1920, 187 FERC ¶ 61,068 at P 996 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 153 ("[T]he ultimate responsibility for transmission planning remains with . . . transmission providers.")).

and the compliance timelines set forth therein.[1213] We deny NARUC's request to require transmission providers to include in their compliance filings any selection criteria that are "promulgated and supported" by Relevant State Entities. That said, we continue to believe that Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation process and selection criteria.[1214] As such, we strongly encourage transmission providers to consider any selection criteria supported by Relevant State Entities.

460. Finally, we grant in part NESCOE's requests for clarification. We believe that "good faith efforts" is a reasonably well-understood standard that parties use in their contractual dealings with one another.[1215] We further believe that the good faith efforts standard is similar to a "reasonable efforts" standard, which can be defined as "one or more actions rationally calculated to achieve a usually stated objective, but not

[1213] *Id.* P 996.

[1214] *Id.* P 996.

[1215] *See Zady Natey, Inc. v. United Food & Comm. Workers Int'l Union, Loc. No. 27*, 995 F.2d 496, 499-500 (4th Cir. 1993) (determining whether contractual counterparty made good faith efforts to perform obligation on the basis of facts developed in adjudicating contractual dispute); *Creative Mktg. Assocs., Inc. v. AT&T*, 476 F.3d 536, 538-39 (8th Cir. 2007) (same); *Zinn v. Parrish*, 644 F.2d 360, 366 (7th Cir. 1981) (same); *Taco Bell Corp. v. Bloor Auto., Inc.*, No. 90-1442, 1991 WL 11618, at *6 (6th Cir. Feb. 5, 1991) (same); *Gulati v. Coyne Int'l Enters. Corp.*, 805 F.Supp. 365, 370-71 (E.D. Va. 1992) (same).

necessarily with the expectation that all possibilities are to be exhausted."[1216] We expect that transmission providers can determine how to apply the "good faith efforts" standard as they consult with and seek support from Relevant State Entities as to the evaluation processes and selection criteria they will use in Long-Term Regional Transmission Planning. Therefore, we find that Order No. 1920 requires transmission providers to provide opportunities for Relevant State Entities to provide input on those proposed processes and to consider that feedback.[1217] We otherwise deny clarification and decline to address NESCOE's hypothetical interpretation of the standard.

### 3. Voluntary Funding

#### a. Order No. 1920 Requirements

461. In Order No. 1920, the Commission required transmission providers in each transmission planning region to include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet transmission providers' selection criteria.[1218]

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[1216] *Reasonable Efforts*, Black's Law Dictionary (12th ed. 2024).

[1217] As the Commission explained in Order No. 1920, however, the transmission provider's failure to obtain Relevant State Entities' support is not necessarily evidence that transmission providers did not exercise good faith efforts to seek their support. Order No. 1920, 187 FERC ¶ 61,068 at P 997.

[1218] *Id.* P 1012.

462. The Commission provided transmission providers with flexibility to propose certain features of such a voluntary funding process in their compliance filings, provided that: (1) the process is transparent and not unduly discriminatory or preferential; and (2) they consult with and seek support from Relevant State Entities when developing such processes.[1219]

463. The Commission further required that transmission providers' proposed OATT provisions must describe: (1) the process by which transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that they receive timely notice and a meaningful opportunity; (2) the period during which Relevant State Entities and interconnection customers may exercise the voluntary funding option; (3) the method that transmission providers will use to determine the amount of voluntary funding required to ensure that the Long-Term Regional Transmission Facility meets the transmission providers' selection criteria; and (4) the mechanism through which transmission providers and Relevant State Entities or interconnection customers will memorialize any voluntary funding agreement.[1220] Finally, the Commission explained that, for any portion of the costs of a selected Long-Term Regional Transmission Facility that is not voluntarily funded, such remaining costs must be allocated according to either the applicable Long-

[1219] *Id.*

[1220] *Id.* P 1013.

Term Regional Transmission Cost Allocation Method or a cost allocation method resulting from a State Agreement Process.[1221]

### b. Requests for Rehearing and Clarification

464. SERTP Sponsors request that the Commission clarify that the requirement in Order No. 1920 that transmission providers include in their OATTs a process to provide Relevant State Entities and interconnection customers with voluntary funding opportunities does not imply that the Commission otherwise is prohibiting voluntary funding in other circumstances.[1222]

### c. Commission Determination

465. In response to SERTP Sponsors' request for clarification, we reiterate that Order No. 1920 does not prohibit voluntary funding approaches that are not described therein.[1223] Transmission providers may seek to demonstrate on compliance that other voluntary funding approaches are consistent with or superior to Order No. 1920's requirements, or they may submit a filing under FPA section 205 to propose such approaches.[1224]

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[1221] *Id.*

[1222] SERTP Sponsors Rehearing Request at 8. SERTP Sponsors further contend that, if the Commission fails to clarify that Order No. 1920 does not prohibit voluntary funding in other circumstances, Order No. 1920 would be arbitrary and capricious and exceed the Commission's authority. *Id.*

[1223] Order No. 1920, 187 FERC ¶ 61,068 at P 1017.

[1224] *Id.* It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has

#### 4. No Selection Requirement

##### a. Order No. 1920 Requirements

466. In Order No. 1920, the Commission stated that it would not require transmission providers to select any particular Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria.[1225] The Commission also prohibited transmission providers from adopting an approach under which they would not select a Long-Term Regional Transmission Facility unless it meets their selection criteria in every Long-Term Scenario and sensitivity.[1226]

##### b. Requests for Rehearing and Clarification

467. SERTP Sponsors request clarification that the Commission's statement, i.e., that "transmission providers may not adopt an approach under which they would not select a Long-Term Regional Transmission Facility unless it meets their selection criteria in every Long-Term Scenario and sensitivity," does not undercut the Commission's determination that Order No. 1920 does not require a transmission provider to select any Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria.[1227] PJM also requests that the Commission clarify that PJM

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not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[1225] Order No. 1920, 187 FERC ¶ 61,068 at P 1026 (citations omitted).

[1226] *Id.* P 968.

[1227] SERTP Sponsors Rehearing Request at 9-10 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 968, 1026).

is not required to select Long-Term Regional Transmission Facilities under any of the Long-Term Scenarios that it develops.[1228]

#### c. Commission Determination

468. In response to SERTP Sponsors' and PJM's requests for clarification, we clarify that Order No. 1920 does not require transmission providers to select any Long-Term Regional Transmission Facility, even where it meets the transmission providers' selection criteria.[1229]

### 5. Reevaluation

#### a. NOPR Proposal

469. The Commission proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility. The Commission proposed that the existing transmission developer requirements would apply, including that the developer of the selected regional transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals necessary to develop and construct the transmission facility such that it meets the transmission needs of the

[1228] PJM Rehearing Request at 19.

[1229] Order No. 1920, 187 FERC ¶ 61,068 at P 1026.

transmission planning region.[1230] The Commission proposed that, to the extent the Relevant State Entities in a transmission planning region agree to a State Agreement Process, the development schedule should also include relevant steps related to that process.[1231]

470. The Commission noted that, given the longer-term nature of transmission needs driven by changes in the resource mix and demand, the required development schedule for a transmission facility selected may make it unnecessary for the developer to take actions or incur expenses in the near-term if the transmission facility will not need to be in service in the near-term. The Commission also noted that a transmission provider may make that Long-Term Regional Transmission Facility's selection status subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles, such that the previously selected transmission facility is no longer needed. The Commission proposed that transmission providers include in their selection criteria how they will

[1230] NOPR, 179 FERC ¶ 61,028 at P 247 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 442). The Commission also stated in Order No. 1000-A that, as part of the ongoing monitoring of the progress of a transmission facility once it is selected, the transmission providers in a transmission planning region must establish a date by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the facility is selected to address. The Commission stated that if such critical steps have not been achieved by that date, then the transmission providers in a transmission planning region may "remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution." Order No. 1000-A, 139 FERC ¶ 61,132 at P 442.

[1231] NOPR, 179 FERC ¶ 61,028 at P 247.

address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles.1232

**b. Order No. 1920 Requirements**

471. In Order No. 1920, the Commission required transmission providers to include in their OATTs provisions that require them to reevaluate previously selected Long-Term Regional Transmission Facilities in three situations, where: (1) delays in the development of a previously selected Long-Term Regional Transmission Facility would jeopardize a transmission provider's ability to meet its reliability needs or reliability-related service obligations; (2) the actual or projected costs of a previously selected Long-Term Regional Transmission Facility significantly exceed cost estimates used in that Long-Term Regional Transmission Facility's selection; or (3) significant changes in federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission provider's selection criteria.[1233] The Commission further required transmission providers to include in these reevaluation provisions the specific criteria they will use to determine when one of these situations occurs.[1234]

472. With respect to reevaluation on the basis of development delays, the Commission explained that Order No. 1920's requirement is the same requirement as that set forth by

[1232] *Id.* P 248.

[1233] Order No. 1920, 187 FERC ¶ 61,068 at PP 1048-1049.

[1234] *Id.* P 1050.

the Commission in Order No. 1000.[1235] The Commission explained that, as is required for regional transmission planning processes under Order No. 1000, transmission providers must have the ability to take action when delays in developing a Long-Term Regional Transmission Facility risk jeopardizing a transmission provider's ability to meet its reliability needs or reliability-related service obligations.[1236]

473. The Commission provided transmission providers with the flexibility to develop these reevaluation criteria1237 provided that, with respect to reevaluation on the basis of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations, transmission providers may not reevaluate a previously selected Long-Term Regional Transmission Facility unless its targeted in-service date was in the latter half of the 20-year transmission planning horizon when it was selected.[1238] The Commission also required that the reevaluation criteria seek to maximize benefits accounting for costs over time without over-building transmission facilities. The Commission further explained that it expected transmission providers to balance the need to provide

[1235] *Id.* P 1049 n.2250. *See id.* P 1033 & n.2224 (explaining that the Commission proposed in the NOPR that existing transmission developer requirements would apply to Long-Term Regional Transmission Planning and that, if a transmission facility's developer did not achieve development milestones, transmission providers may remove that facility from the regional transmission plan and reevaluate the regional transmission plan to seek an alternative solution).

[1236] *Id.* P 1056.

[1237] *Id.*

[1238] *Id.* P 1051.

transmission developers with adequate investment certainty, absent which more efficient or cost-effective Long-Term Regional Transmission Facilities will not be developed, against the risk that, due to significant changes in circumstances, failing to reevaluate a selected Long-Term Regional Transmission Facility may result in the over-building of transmission.[1239] The Commission also required transmission providers to designate a point after which all selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation—e.g., when the facility's transmission developer has secured all relevant permits and authorizations—such that the transmission developer of the selected Long-Term Regional Transmission Facility has adequate certainty to make investment decisions.[1240]

474. The Commission further required transmission providers to include in their OATTs provisions detailing the process and procedures they will use to reevaluate a previously selected Long-Term Regional Transmission Facility, including the potential outcomes of reevaluation (e.g., taking no action, imposing a mitigation plan, reassigning the Long-Term Regional Transmission Facility to a different transmission developer, modifying the Long-Term Regional Transmission Facility, or removing the Long-Term Regional Transmission Facility from the regional transmission plan), and in particular the

[1239] *Id.* P 1050.

[1240] *Id.*

conditions under which they would remove a previously selected Long-Term Regional Transmission Facility from the regional transmission plan.[1241]

475. The Commission otherwise allowed flexibility as to the design of the reevaluation processes and procedures, subject to three requirements.[1242] First, the Commission stated that any reevaluation on the basis of cost increases or of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations must occur in a subsequent Long-Term Regional Transmission Planning cycle and must take into account not only the updated costs but also the updated benefits of the Long-Term Regional Transmission Facility.[1243] The Commission stated that, when performing these reevaluations, it expected that transmission providers will use the updated Long-Term Scenarios and associated transmission system models that are developed for the Long-Term Regional Transmission Planning cycle in which the transmission provider reevaluates the selected Long-Term Regional Transmission Facility.[1244] Second, the Commission required

[1241] *Id.* P 1052 (citing MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § IX.E, which sets forth potential outcomes of MISO's variance analysis procedures).

[1242] *Id.*

[1243] *Id.*; *see also id.* P 1059 (explaining that the requirement that the reevaluation processes and procedures update not only actual and projected costs but also their calculation of the benefits of the selected Long-Term Regional Transmission Facility will ensure that transmission providers compare the updated costs and benefits when determining whether the Long-Term Regional Transmission Facility continues to be a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs).

[1244] *Id.* P 1052 n.2254.

transmission providers to include in the reevaluation processes and procedures mechanisms for tracking the costs of Long-Term Regional Transmission Facilities.[1245] Third, the Commission required that the reevaluation processes and procedures seek to maximize benefits accounting for costs over time without over-building transmission facilities.1246

### c. Requests for Rehearing and Clarification

#### i. Logical Outgrowth

476. Several parties argue that the Commission did not provide sufficient notice of, and opportunity to comment on, Order No. 1920's reevaluation requirements.1247 For example, EEI claims that the Commission cannot require transmission providers to adopt OATT provisions that require them to reevaluate previously selected Long-Term Regional Transmission Facilities without providing notice of and an opportunity to comment on these requirements.1248 EEI argues that Order No. 1920's reevaluation requirements are not within the scope of the NOPR's reevaluation proposal and therefore were not "reasonably foreseeable" by interested parties and that these requirements

[1245] *Id.* P 1052.

[1246] *Id.*

[1247] East Kentucky Rehearing Request at 1-2; EEI Rehearing Request at 4-11; ITC Rehearing Request at 16; MISO TOs Rehearing Request at 8, 19-22; NRECA Rehearing Request at 13-15, 22; WIRES Rehearing Request at 2-4, 6-16.

[1248] EEI Rehearing Request at 5.

cannot stand because they are not a logical outgrowth of the NOPR proposal.[1249] EEI notes that the Commission stated in Order No. 1920 that a number of parties expressed support for the reevaluation requirements in their NOPR comments but contends that applicable precedent makes clear that comments on the proposed rule are not a substitute for the Commission itself providing notice of its intention to impose these requirements.[1250] EEI further notes that the Commission has invited consideration of the reevaluation of previously selected transmission facilities in a different proceeding and states that it would have been more appropriate for the Commission to have acted in that proceeding rather than in Order No. 1920 because the NOPR lacked any description of the range of reevaluation alternatives.[1251] EEI states that it does not oppose "reasonable mechanisms" to protect consumers from over-building Long-Term Regional Transmission Facilities and from the possibility of building transmission facilities that may not be cost-effective, but asserts that the appropriate remedy in this instance is to return to the NOPR proposal.[1252]

477. NRECA argues that Order No. 1920 departs from the NOPR proposal by adopting "completely new" requirements for the reevaluation of previously selected Long-Term

[1249] *Id.* at 6-7 (citing *Brennan v. Dickson*, 45 F.4th at 69-70).

[1250] *Id.* (citing *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983)).

[1251] *Id.* at 10 (citing Notice Inviting Post-Technical Conference Comments, *Transmission Planning and Cost Mgmt.*, Docket No. AD22-8-000, et al. (Dec. 23, 2022)).

[1252] *Id.* at 10-11.

Regional Transmission Facilities.[1253] NRECA contends that the reevaluation requirements result in an "inflexible, final selection of Long-Term Regional Transmission Facilities for purposes of regional cost allocation in the first three years of each Long-Term Regional Transmission Planning cycle."[1254] NRECA recommends that, to ensure compliance with the APA's notice-and-comment requirements, the Commission withdraw the final rule and issue a supplemental NOPR.[1255]

478. WIRES asserts that the NOPR did not provide notice to interested parties of Order No. 1920's "detailed and prescriptive" reevaluation requirements and that these requirements represent major changes from the NOPR proposal.[1256] WIRES asserts that the reevaluation requirements are significant because they could lead to modifying Long-Term Regional Transmission Facilities or removing them from the regional transmission plan, and, as such, the Commission should have clearly and unambiguously set forth a proposal in the NOPR before adopting Order No. 1920's reevaluation requirements.[1257] WIRES alleges that instead, the Commission adopted "almost word-for-word" a proposal

[1253] NRECA Rehearing Request at 4-6.

[1254] *Id.* at 14.

[1255] *Id.* at 4, 19.

[1256] WIRES Rehearing Request at 3-5.

[1257] *Id.* at 2-4.

submitted in comments by Large Public Power without first providing notice of and an opportunity to comment on this proposal.[1258]

479. Several rehearing parties contend that, while the NOPR proposed a structure that would permit but not require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities, Order No. 1920 requires that transmission providers do so and includes a number of prescriptive requirements that were not included in the NOPR.[1259] MISO TOs argue that Order No. 1920 states that it adopted with modification the NOPR proposal, despite the fact that the NOPR proposed a "flexible and open-ended opportunity" in accordance with which transmission providers could have tailored their compliance proposals, whereas Order No. 1920's reevaluation requirements are "a wholly new and tightly prescriptive process with new triggering events and new requirements for reassessing facilities."[1260] WIRES notes that the NOPR did not use the term "reevaluate," that it proposed to provide flexibility for transmission providers to propose their own processes, and did not include any relevant details or requirements other than to propose that transmission providers "should include in their selection criteria how they will address the selection status of a previously

[1258] *Id.* at 10.

[1259] *See, e.g.*, EEI Rehearing Request at 7-8; WIRES Rehearing Request at 7-8.

[1260] MISO TOs Rehearing Request at 21-22 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1048).

selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles."[1261]

480. Several parties acknowledge that, in setting forth Order No. 1920's reevaluation requirements, the Commission cited the NOPR proposal that would have allowed transmission providers to make the selection status of previously selected Long-Term Regional Transmission Facilities subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles,[1262] but contend nonetheless that that notice was inadequate. EEI states that the NOPR proposal contained none of the detail or the rationale regarding specific elements of Order No. 1920's reevaluation requirements, such as the specific situations in which reevaluation would be required or the requirement for transmission providers to include in their OATTs the potential outcomes of reevaluation.[1263] EEI further argues that, whereas the NOPR proposal focused on how the outcome of subsequent Long-Term Regional Transmission Planning cycles could give rise to the need to reevaluate, the three situations in which Order No. 1920 requires reevaluation do not depend on the results of or actions in a subsequent Long-Term Regional Transmission Planning cycle.[1264]

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[1261] WIRES Rehearing Request at 6-7 (quoting NOPR, 179 FERC ¶ 61,028 at P 248).

[1262] *See* NOPR, 179 FERC ¶ 61,028 at P 248.

[1263] EEI Rehearing Request at 5-6.

[1264] *Id.* at 8-9.

481. NRECA states that it did not oppose the Commission's NOPR proposal to require transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning—and particularly, the requirements that transmission providers use a 20-year transmission planning horizon and measure the benefits of transmission facilities over 20 years—because of the NOPR proposal to allow transmission providers to subject the selection status of Long-Term Regional Transmission Facilities to the outcome of subsequent Long-Term Regional Transmission Planning cycles.[1265] NRECA states that it interpreted the NOPR as allowing transmission providers to develop selection criteria under which transmission providers could conditionally select a Long-Term Regional Transmission Facility but delay selecting that Facility for purposes of cost allocation until later.[1266] NRECA states that the Commission did not adopt the NOPR proposal and instead adopted "completely different, prescriptive [reevaluation] requirements."[1267]

482. MISO TOs and ITC each argue that the Commission did not provide adequate notice of or an opportunity to comment on the requirement that transmission providers update their measurement of the benefits of Long-Term Regional Transmission Facilities. MISO TOs state that the NOPR proposed "the option of a routine review" and did not

[1265] NRECA Rehearing Request at 13 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[1266] *Id.* at 24.

[1267] *Id.* at 25 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1055 & n.2257).

include any requirement for a "general reevaluation of benefits of the facilities," and that this deprived regulated parties of the fair notice required by the APA.[1268] ITC contends that Order No. 1920's reevaluation requirements depart substantially from the original reevaluation proposal, and that the Commission has not provided commenters a meaningful opportunity to comment on the requirement "to perform a full update of the calculation of the benefits" resulting in a factual record that does not address the relative merits of this approach.[1269]

483. MISO TOs and WIRES each argue that, had the Commission provided notice of and an opportunity to comment, Order No. 1920's reevaluation requirements would ultimately have been improved. MISO TOs argue that Order No. 1920 is not as clear or as workable as it might have been if MISO TOs and other commenters had fair notice, and that the Commission instead could have adopted "a more nuanced and workable requirement."[1270] WIRES claims that the Commission did not have the benefit of sufficient input from regulated parties. WIRES contends that, while the Commission stated that it set forth Order No. 1920's reevaluation requirements having "carefully reviewed the record developed here and weighed commenters' countervailing

[1268] MISO TOs Rehearing Request at 19-21.

[1269] ITC Rehearing Request at 16.

[1270] MISO TOs Rehearing Request at 19, 22.

arguments," the comments submitted were specific to the NOPR proposal that was not adopted—not Order No. 1920's reevaluation requirements.1271

### ii. Other Issues

484. Several parties sought rehearing or clarification of the requirement to update the measurement of benefits when reevaluating a previously selected Long-Term Regional Transmission Facility or Facilities.[1272] MISO TOs argued that the requirement for transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities risks significant disruption to the use of portfolio approaches to selecting such facilities. MISO TOs argued that the Commission had not provided substantial evidence to support requiring transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities during reevaluations, as the Commission acknowledged that updating the measurement of benefits is "not as straightforward as tracking costs," reassessing benefits is different than reassessing costs, and reevaluation could create "unnecessary disruptions and potentially impede the efficient conduct" of Long-Term Regional Transmission Planning.[1273] MISO TOs requested that, on rehearing, the Commission modify Order No. 1920's requirement

[1271] WIRES Rehearing Request at 14-16 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1053).

[1272] MISO TOs Rehearing Request at 4; ITC Rehearing Request at 17; WIRES at 11-12.

[1273] MISO TOs Rehearing Request at 17-19 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1059).

such that transmission providers would "consider benefits and the broader needs of the region in the reevaluation process and choose an outcome based on that assessment."[1274]

485. ITC argued that, while reevaluating a previously selected Long-Term Regional Transmission Facility on the basis of cost increases is reasonable, Order No. 1920's requirement for transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities will burden transmission providers and deter investment in such facilities. ITC therefore requested that the Commission eliminate the requirement to update the measurement of the benefits or, in the alternative, clarify that transmission providers may adopt a more qualitative assessment that takes into account the benefits and costs of a Long-Term Regional Transmission Facility in the context of the transmission planning region's Long-Term Transmission Needs, and also that transmission providers may adopt flexible remedial measures such as those available under MISO's variance analysis process.[1275] Similarly, WIRES requested clarification as to whether Order No. 1920 would allow transmission providers flexibility to determine how they will update their measurement of the benefits of Long-Term Regional Transmission Facilities, and argued that transmission providers should have the flexibility to address the concerns raised by the Commission in developing their reevaluation criteria in a manner compatible with their transmission planning process.[1276]

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[1274] *Id.* at 13.

[1275] ITC Rehearing Request at 15-19.

[1276] WIRES Rehearing Request at 14.

486. NRECA requested that the Commission eliminate the requirement for transmission providers to designate a point after which all previously selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation, i.e., a pencils-down point, such that the transmission developer of the selected facility would have adequate certainty to make investment decisions.[1277]

487. Large Public Power and NRECA requested that the Commission require on rehearing that transmission providers reevaluate previously selected Long-Term Regional Transmission Facilities not only when there is a significant increase in costs, but also when there is a significant decrease in the benefits of a particular facility.[1278] Large Public Power further requested that the Commission clarify that Order No. 1920 requires transmission providers to track both the costs and the benefits of previously selected Long-Term Regional Transmission Facilities.[1279] In addition to reevaluation on the basis of cost increases, NRECA argued that transmission providers should be required to

[1277] NRECA Rehearing Request at 33 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1050); *see also* East Kentucky Rehearing Request at 2 (arguing that Order No. 1920 permits arbitrary and unreasonable deadlines on reevaluations).

[1278] Large Public Power Rehearing Request at 17-19; NRECA Rehearing Request at 29-30; *see also* East Kentucky Rehearing Request at 2 (arguing that the Order No. 1920 requirement related to reevaluation on the basis of cost increases is "too narrowly drawn" and inconsistent with other aspects of Order No. 1920).

[1279] Large Public Power Rehearing Request at 17-18 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 1054, 1059).

reevaluate previously selected Long-Term Regional Transmission Facilities when the transmission planning region's Long-Term Transmission Needs have changed.[1280]

488. ITC, Large Public Power, and NRECA argued that the Commission should grant rehearing and eliminate Order No. 1920's requirements to reevaluate on the basis of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations, because these requirements are either too narrow or too broad.[1281]

489. ITC stated that Order No. 1920 encourages the use of portfolio approaches to select Long-Term Regional Transmission Facilities, as they generate considerable interdependency among the various Long-Term Regional Transmission Facilities selected in a particular Long-Term Regional Transmission Planning cycle. ITC therefore recommended that the Commission require periodic project portfolio reporting modeled after MISO's Multi-Value Project Triennial Reporting framework, which ITC contended provides a regular check to ensure transmission customers receive the benefits they are promised and allows for regional transmission planning process improvement.1282 If the Commission did not grant rehearing and eliminate reevaluations on the basis of significant changes in law or regulations, ITC requested that the Commission allow such

[1280] NRECA Rehearing Request at 30-32.

[1281] ITC Rehearing Request at 4-5; Large Public Power Rehearing Request at 19-20; NRECA Rehearing Request at 36; *see also* East Kentucky Rehearing Request at 2 (stating that Order No. 1920 "arbitrarily [and] unreasonably prohibits some reevaluations due to changes in laws or regulations").

[1282] ITC Rehearing Request at 13-14.

reevaluation only for Long-Term Regional Transmission Facilities whose targeted in-service date is more than 10 years from the point at which the transmission provider conducts the reevaluation.

490. In contrast, Large Public Power argued that the "blanket ten-year moratorium" is arbitrary and capricious.[1283] NRECA argued that the Commission provided no rationale for this limitation, which it characterized as "so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[1284]

491. Several parties requested that the Commission provide transmission providers with more flexibility to reevaluate previously selected Long-Term Regional Transmission Facilities in other situations. Dominion sought rehearing or, as applicable, clarification of the Commission's reevaluation process to allow transmission providers to reevaluate a previously selected Long-Term Regional Transmission Facility in situations other than those identified in Order No. 1920.1285 Similarly, SERTP Sponsors requested that the Commission clarify that the three situations described in Order No. 1920 in which reevaluation of previously selected Long-Term Regional Transmission Facilities is required are illustrative, arguing that Order No. 1920 grants transmission providers

[1283] Large Public Power Rehearing Request at 19-20.

[1284] NRECA Rehearing Request at 36 (quoting *State Farm*, 463 U.S. at 43).

[1285] Dominion Rehearing Request at 17.

inadequate flexibility in developing OATT provisions regarding the reevaluation of previously selected Long-Term Regional Transmission Facilities.[1286]

### d. Commission Determination

#### i. Logical Outgrowth

492. We disagree with the argument that the Commission failed to provide adequate notice of and opportunity to comment on Order No. 1920's requirement that transmission providers include provisions in their OATTs that require them to reevaluate previously selected Long-Term Regional Transmission Facilities in certain circumstances. As the D.C. Circuit explained recently, "the very premise of agencies' duty to solicit, consider, and respond appropriately to comments is that rules evolve from conception to completion."1287 Indeed, notice is sufficient if the final rule represents a "logical outgrowth" of the proposed rule.[1288] Order No. 1920's reevaluation requirements are closely related to and fully in character with the NOPR proposal, and represent the kind of reasonable evolution of an initial proposal in response to comments that rehearing parties could have reasonably anticipated.

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[1286] SERTP Sponsors Rehearing Request at 20-21.

[1287] *Brennan v. Dickson*, 45 F.4th at 69.

[1288] *Long Island Care*, 551 U.S. at 174-75. *See also Am. Paper Inst. v. EPA*, 660 F.2d at 959 n.13 ("An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.") (emphasis added).

493. As an initial matter, we note that the NOPR proposed to require the reevaluation of previously selected transmission facilities in certain circumstances. Because Long-Term Regional Transmission Planning is a form of regional transmission planning,[1289] the Commission's regional transmission planning requirements apply. This includes a requirement that transmission providers describe in their OATTs the circumstances in which and the procedures under which transmission providers will conduct a reevaluation. This reevaluation is necessary to determine how a transmission provider will respond if development delays affecting a previously selected regional transmission facility jeopardize incumbent transmission owners' ability to meet their reliability needs or service obligations.1290 The Commission made this explicit in the NOPR when it proposed that Order No. 1000's transmission developer requirements would apply to Long-Term Regional Transmission Planning[1291] and noted that in the event of development delays, transmission providers may "remove the transmission facility from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution."[1292]

[1289] NOPR, 179 FERC ¶ 61,028 at P 68; Order No. 1920, 187 FERC ¶ 61,068 at P 224.

[1290] Order No. 1000, 136 FERC ¶ 61,051 at P 329.

[1291] NOPR, 179 FERC ¶ 61,028 at P 247.

[1292] *Id.* P 247 n.395 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 442).

494. The Commission further proposed in the NOPR to allow transmission providers to make the selection status of a previously selected Long-Term Regional Transmission Facility "subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles," such that it "is no longer needed" and proposed that transmission providers "should include in their selection criteria how they will address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles."[1293] The Commission suggested that this proposal was warranted because the development schedule for a Long-Term Regional Transmission Facility may not require its developer to undertake actions or incur expenses in the near-term,[1294] and it explained that the NOPR's proposed reforms were intended to be responsive to "commenters' concerns about over-building [transmission facilities] due to uncertainties of future transmission system conditions."[1295] Therefore, although the Commission used other language, the Commission effectively proposed in the NOPR that transmission providers could reevaluate certain Long-Term Regional Transmission Facilities (i.e., those for which near-term development activities are not necessary) in light of changed circumstances apparent in the subsequent Long-

[1293] *Id.* P 248.

[1294] *Id.*

[1295] NOPR, 179 FERC ¶ 61,028 at P 245.

Term Regional Transmission Planning cycle to determine whether to continue developing that facility or find that it was no longer needed.1296

495. In other words, the NOPR provided adequate notice of and an opportunity to comment on proposals to require reevaluation of previously selected Long-Term Regional Transmission Facilities due to development delays and to permit reevaluation of previously selected Long-Term Regional Transmission Facilities due to changed circumstances from one Long-Term Regional Transmission Planning cycle to the next.

496. Commenters objected to the NOPR proposal on the grounds that providing open-ended allowance for reevaluation of previously selected Long-Term Regional Transmission Facilities would undermine selection as a "reasonably final" step and create too much uncertainty for transmission developers, which would impede the development of the relevant transmission facilities and ultimately could raise concerns about reliability impacts or other consequences.[1297] Upon consideration of the record before it and these comments in particular, the Commission modified the NOPR proposal to allow for the reevaluation of previously selected Long-Term Regional Transmission Facilities due to changed circumstances from one transmission planning cycle to the next. Specifically, Order No. 1920 required the reevaluation of Long-Term Regional Transmission Facilities only in certain circumstances that could affect the need for the facility—i.e., where the costs of the transmission facility significantly exceed estimates or where significant

[1296] *Id.* P 248.

[1297] Order No. 1920, 187 FERC ¶ 61,068 at P 1055 & n.2256.

changes in federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that the facility no longer meets selection criteria.[1298] Further, consistent with the Commission's reasoning in the NOPR that reevaluation may be appropriate where near-term development actions or expenditures are not needed in order to meet the targeted in-service date, the Commission limited the availability of reevaluation due to significant changes in laws or regulations to only those facilities that are not needed to be in-service within 10 years (i.e., unless its targeted in-service date was in the latter half of the 20-year transmission planning horizon during the Long-Term Regional Transmission Planning cycle in which it was selected) and required a "pencils-down" point in the development of a facility at which reevaluation would no longer be permitted.[1299] The Commission's modifications are not "surprisingly distant" from the proposal so as to be wholly unexpected;[1300] instead, the changes merely refine the proposals included in the NOPR and are thus precisely the kind of tailoring and fine-tuning of a proposed rule in response to comments that is the *raison d'être* for APA notice-and-comment requirements.[1301]

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[1298] *Id.* PP 1048-1055.

[1299] *Id.* PP 1050-1051.

[1300] *Brennan v. Dickson*, 45 F.4th at 69.

[1301] We note that, while the reevaluation requirements are one tool to manage the inherent uncertainties of Long-Term Regional Transmission Planning and to limit the risk of over-building transmission in response to speculative transmission needs, we believe that other requirements in Order No. 1920 also address these concerns. The inability to include reevaluation requirements would not have prevented the Commission from

### ii. Other Issues

497. We also disagree with rehearing parties' substantive objections to the reevaluation requirements. While certain parties object to the reevaluation requirements as too lax,1302 and other parties object to them as too stringent,1303 we conclude that they strike a reasonable balance between providing adequate certainty to transmission developers to support capital investment, such that more efficient or cost-effective Long-Term Transmission Facilities actually may be developed, and mitigating the inherent uncertainty involved in Long-Term Regional Transmission Planning, given that continued selection of Long-Term Regional Transmission Facilities that no longer meet selection criteria could be costly to consumers.1304 Specifically, though several rehearing parties object that reevaluation should be required in additional circumstances, such as whenever there is a reduction in benefits,[1305] whenever there is a change in transmission needs,1306 or at points of time beyond the "pencils-down" date,[1307] and

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issuing Order No. 1920.

[1302] *See e.g.*, East Kentucky Rehearing Request at 2; NRECA Rehearing Request at 33.

[1303] *See e.g.*, ITC Rehearing Request at 15-19; MISO TOs Rehearing Request at 17-19.

[1304] Order No. 1920, 187 FERC ¶ 61,068 at P 1054.

[1305] Large Public Power Rehearing Request at 17-19; NRECA Rehearing Request at 29-30.

[1306] NRECA Rehearing Request at 30-32.

[1307] *Id.* at 33.

others argue that the transmission provider should have more discretion to determine when to reevaluate previously selected Long-Term Regional Transmission Facilities,[1308] we continue to find that such open-ended allowance for reevaluation would fail to account for the degree of certainty that is needed to support capital investment, and would therefore fail to adequately ensure development of more efficient or cost-effective Long-Term Regional Transmission Facilities.1309

498. On the other hand, we also reject requests to eliminate the requirement to reevaluate facilities where significant changes in laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission provider's selection criteria.1310 We remain concerned that, absent an opportunity to determine whether selection of such a facility remains warranted in light of a significant change in laws or regulations, transmission providers may be reluctant to select certain Long-Term Regional Transmission Facilities,[1311] and we find that requiring reevaluation in such a circumstance helps to mitigate the inherent uncertainty of Long-Term Regional Transmission Planning and the risk of over-building transmission facilities. With the limitations we impose—i.e., that such reevaluation only

[1308] Dominion Rehearing Request at 17; SERTP Sponsors Rehearing Request at 20-21.

[1309] Order No. 1920, 187 FERC ¶ 61,068 at P 1053.

[1310] ITC Rehearing Request at 4-5.

[1311] Order No. 1920, 187 FERC ¶ 61,068 at P 1056.

occur for facilities with a targeted in-service date that is in the latter half of the Long-Term Regional Transmission Planning cycle in which it is selected and that reevaluation may only occur up to the "pencils-down" point in the facility's development—we are not persuaded that reevaluation under these circumstances will create such uncertainty for transmission developers as to significantly impede the development of more efficient of cost-effective Long-Term Regional Transmission Facilities.

499. While we appreciate rehearing parties' concerns that assessing a change in a transmission facility's benefits is more complex than assessing a change in its costs, we decline requests to set aside the requirement to account for updated benefits when transmission providers reevaluate a Long-Term Regional Transmission Facility based on a significant increase in the facility's estimated costs.1312 We continue to find that such a requirement will help to ensure there is an opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities, because otherwise the transmission provider would compare the facility's currently determined costs with its previously determined benefits.[1313]

500. We further find that rehearing parties' concerns about the burdens of accounting for updated benefits are misplaced, as Order No. 1920 provided significant flexibility to transmission providers as to how to account for changes in benefits. While Order No. 1920 requires that such reevaluations must only occur during a subsequent Long-Term

[1312] MISO TOs Rehearing Request at 17-19; ITC Rehearing Request at 15-19.

[1313] Order No. 1920, 187 FERC ¶ 61,068 at P 1059.

Regional Transmission Planning cycle (i.e., rather than in between such cycles) because doing so during such a cycle enables transmission providers to make use of updated assumptions, inputs, and the Long-Term Scenarios that must be developed in any event during the subsequent cycle, Order No. 1920 does not prescribe any particular method for assessing updated benefits.[1314] We note that, because Order No. 1920 provides transmission providers the flexibility to propose qualitative measures in their evaluation processes and qualitative selection criteria, transmission providers will need flexibility to develop a process for determining if a previously selected Long-Term Regional Transmission Facility continues to meet those selection criteria.

501. We are also not persuaded by rehearing parties' arguments that the reevaluation requirements will undermine the ability of transmission providers to use a portfolio approach to evaluating benefits or selecting Long-Term Regional Transmission Facilities.[1315] As described above, transmission providers have significant flexibility to determine how to update benefits, and they may propose to use a method that accommodates Order No. 1920's reevaluation requirements in the context of portfolio approaches to selecting Long-Term Regional Transmission Facilities. Likewise, provided the process seeks to maximize benefits accounting for costs over time without over-building transmission facilities, transmission providers have significant flexibility to

[1314] This clarification resolves WIRES's request for clarification regarding the flexibility allowed transmission providers to determine how to account for updated benefits. *See* WIRES Rehearing Request at 14.

[1315] ITC Rehearing Request at 6-9; MISO TOs Rehearing Request at 17-19.

determine the appropriate outcomes that may result from reevaluation, including the potential mitigation measures that may be regionally appropriate.1316 Thus, transmission providers have scope to tailor both how reevaluation is conducted and the outcomes of the reevaluation process to the portfolio approach.

### E. Implementation of Long-Term Regional Transmission Planning

#### 1. Order No. 1920 Requirements

502. In Order No. 1920, the Commission required transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. The Commission required transmission providers to provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, the Commission required transmission providers to address the possible interaction between the transmission planning cycles for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. The Commission recognized that there may be overlap in the time horizon for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes and that these processes will likely inform each other.[1317] Second, the Commission required transmission providers to address the possible displacement of regional transmission facilities from the existing

[1316] Order No. 1920, 187 FERC ¶ 61,068 at P 1052.

[1317] *Id.* P 1071.

regional transmission planning processes. The Commission recognized that it is possible that, in some cases, Long-Term Regional Transmission Facilities selected to address Long-Term Transmission Needs may provide near-term reliability or economic benefits, and thus could displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.[1318]

503. The Commission found that transmission providers should have the flexibility to integrate the existing regional transmission planning processes with Long-Term Regional Transmission Planning in a manner that mitigates the potential for disruption of the existing regional transmission planning processes. However, the Commission expressed concern that too much flexibility for transmission providers with respect to the date by which they must begin the first Long-Term Regional Transmission Planning cycle could lead to unnecessary delay in realizing these beneficial reforms for customers. Thus, the Commission required transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. The Commission stated that transmission providers in a transmission planning region may propose to start the first Long-Term Regional Transmission Planning cycle on a date later than one year from the initial compliance filing due date, only to the extent needed to align the Long-Term Regional

[1318] *Id.*

Transmission Planning cycle with existing transmission planning cycles.[1319] While the Commission encouraged transmission providers to align transmission planning cycles if useful, to ensure that there is no inappropriate delay to starting Long-Term Regional Transmission Planning, the Commission stated that transmission providers in a transmission planning region that propose a commencement date of later than one year from the compliance due date must include adequate support explaining how the proposed date to begin the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region.[1320]

504. The Commission encouraged transmission providers to address in their explanations how their proposed Long-Term Regional Transmission Planning would facilitate moving beyond piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.[1321]

### 2. Requests for Rehearing and Clarification

505. PJM states that it recognizes that the long-term transmission planning horizon can and will inform Order No. 1000 processes but argues that it is imperative that these two processes function effectively together so that PJM can respond to short-term needs quickly and nimbly.[1322] Accordingly, PJM requests flexibility in designing its Long-

[1319] *Id.* P 1072.

[1320] *Id.*

[1321] *Id.* P 1073.

[1322] PJM Rehearing Request at 41.

Term Regional Transmission Planning process in a way that would minimize harmful interaction from the overlap between Order No. 1000 and Order No. 1920 regional transmission planning processes and would allow for the efficient use of PJM's resources.[1323]

506. TAPS asserts that Order No. 1920 does not adequately clarify how the Order No. 1000 economic and reliability processes and the Long-Term Regional Transmission Planning process will interact after the initial implementation phase.[1324] TAPS argues that Order No. 1920 does not address whether, or the circumstances under which, transmission projects may be moved from an Order No. 1000 reliability or economic planning process to the Long-Term Regional Transmission Planning process, or vice versa.[1325] As a result, TAPS requests that the Commission recognize that these regional transmission planning processes will continue to interact after the initial implementation of Long-Term Regional Transmission Planning and require that transmission providers demonstrate how these processes will interact on an ongoing basis, including how and when transmission projects may be moved between the two processes.[1326]

[1323] *Id.*

[1324] TAPS Rehearing Request at 6-9.

[1325] *Id.* at 8.

[1326] *Id.* at 6-9.

### 3. Commission Determination

507. As an initial matter, upon further consideration, we set aside, in part, Order No. 1920's requirement that transmission providers in each transmission planning region must propose on compliance a date, no later than one year from the date on which initial filings to comply with the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle.[1327] Instead, we require that transmission providers must propose on compliance a date, no later than *two* years from the date on which initial filings to comply with Order No. 1920 are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. We find that this modification balances the need to ensure that transmission providers timely implement Order No. 1920's requirements to avoid unnecessary delay in realizing these beneficial reforms for customers, as explained in Order No. 1920,[1328] with the need to provide transmission providers with sufficient time to implement Long-Term Regional Transmission Planning and align the Long-Term Regional Transmission Planning cycle with existing transmission planning cycles, which may be longer than a single year.

508. Moreover, we modify Order No. 1920's requirement that transmission providers that propose a commencement date of later than one year from the compliance due date must include adequate support explaining how the proposed date to begin the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for

[1327] Order No. 1920, 187 FERC ¶ 61,068 at P 1072.

[1328] *See id.*

their transmission planning region.[1329] Instead, we require that regardless of the date that transmission providers propose on compliance, they must explain in their compliance filing why the proposed date on which they will commence the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region. We find that this modification will allow the Commission to ensure that the proposed date will not unnecessarily delay the realization of Order No. 1920's beneficial reforms for customers.

509. We sustain the requirement that transmission providers must explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning will interact with the existing regional transmission planning processes under Order No. 1000. As the Commission recognized in Order No. 1920, there may be overlap in the time horizons for these processes, and transmission providers should have the flexibility to integrate the existing regional transmission planning processes with Long-Term Regional Transmission Planning in a manner that mitigates the potential for disruption of the existing regional transmission planning processes.[1330] While Long-Term Regional Transmission Planning processes must still meet all requirements set forth in Order No. 1920, we believe that this flexibility extends to and addresses concerns raised by PJM, including its request for flexibility to design its Long-Term Regional

[1329] *See id.*

[1330] *Id.*

Transmission Planning process in a way that minimizes potential harmful impacts to existing regional transmission planning processes.

510. In response to TAPS' request for rehearing, we recognize that Long-Term Regional Transmission Planning and existing Order No. 1000 economic and reliability transmission planning processes may continue to interact after the initial implementation of Long-Term Regional Transmission Planning. However, while this interaction is possible, we believe that, after the first Long-Term Regional Transmission Planning cycle concludes, the overlap between the existing Order No. 1000 regional transmission planning processes and Long-Term Regional Transmission Planning will likely diminish. As the Commission found in Order No. 1920, existing regional transmission planning processes that plan for reliability and economic transmission needs may in the future come to address only residual needs not already addressed through Long-Term Regional Transmission Planning.[1331] As a result, the potential for overlap between Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning process should decrease. Further, we do not believe that it is necessary to require transmission providers to explain how a transmission facility selected in one regional transmission process may "move" to another regional transmission planning process. Nevertheless, as the Commission stated in Order No. 1920, we encourage transmission providers to address in their explanation on compliance how their proposed Long-Term Regional Transmission Planning process will facilitate moving beyond

[1331] *Id.* P 245.

piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.[1332]

## VI. Coordination of Regional Transmission Planning and Generator Interconnection Processes

### A. Need for Reform and Overall Requirement

#### 1. Order No. 1920 Requirements

511. In Order No. 1920, the Commission found that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not adequately consider certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been resolved due to the withdrawal of the underlying interconnection request(s).1333 The Commission made this finding in response to (among other things) evidence in the record that the level of spending on interconnection-related network upgrades has dramatically increased in recent years and evidence that this trend leads to more interconnection requests withdrawing in the face of significant costs associated with interconnection-related network upgrades.1334 The Commission stated that, while interconnection customers may choose to withdraw from the interconnection queue for a number of reasons, in recent years, the deciding factor has increasingly

[1332] *Id.* P 1073.

[1333] Order No. 1920, 187 FERC ¶ 61,068 at P 1100.

[1334] *Id.* P 1101.

become the interconnection customer's sticker shock at its cost responsibility for interconnection-related network upgrades.[1335] The Commission also based its finding on evidence that in many cases when an interconnection-related transmission need is not addressed via development of interconnection-related network upgrades in one interconnection queue cycle, the same interconnection-related transmission need—and oftentimes the same or a substantially similar interconnection-related network upgrade—will appear in subsequent interconnection queue cycles.[1336]

512. Consequently, the Commission adopted requirements for transmission providers in each transmission planning region to revise their regional transmission planning processes in their OATTs to evaluate for selection regional transmission facilities that address certain interconnection-related transmission needs associated with specific interconnection-related network upgrades originally identified through the generator interconnection process. In particular, the Commission adopted four qualifying criteria for when transmission providers must evaluate interconnection-related transmission needs in the regional transmission planning process. The Commission found that this requirement will ensure that more efficient or cost-effective transmission expansion can be effectuated through regional transmission planning processes and will eliminate a potential barrier to entry for new generation resources, thereby enhancing competition in wholesale electricity markets and facilitating access to lower-cost generation. The

[1335] *Id.*

[1336] *Id.* P 1102.

Commission stated that, as a result, this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.[1337]

### 2. Requests for Rehearing

513. SERTP Sponsors, Large Public Power, and Industrial Customers argue that this reform is premature in light of Order No. 2023, which is intended to, among other things, reduce speculative interconnection requests and withdrawals.[1338] SERTP Sponsors argue that the Commission should grant rehearing and revisit this reform after experience is gained to determine whether interconnection withdrawals could "reasonably be expected to be indicative of a need for new regional transmission facilities that have 'a voltage of at least 200 kV and an estimated cost of at least $30 million.'"[1339] SERTP Sponsors argue that accordingly, the Commission has not established a rational basis supported by substantial evidence for this requirement.[1340]

514. PJM argues that the Commission failed to provide substantial evidence for its conclusion that, nationwide, the deciding factor for interconnection customers'

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[1337] *Id.* PP 1106, 1145.

[1338] SERTP Sponsors Rehearing Request at 22; Large Public Power Rehearing Request at 23; Industrial Customers Rehearing Request at 46-47.

[1339] SERTP Sponsors Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1145).

[1340] *Id.* at 22-23 (citing *Samaritan Health Serv. v. Bowen*, 811 F.2d 1524, 1528 (D.C. Cir. 1987) (finding that agency's classification of costs had "no rational basis" and was, therefore, arbitrary and capricious)).

withdrawals is sticker shock at their assigned network upgrade costs.[1341] PJM argues that the Commission ignored its analysis of more than 700 interconnection requests in one transmission zone over a six-year period that demonstrated that only 14 requests or 2% would have likely met the voltage and cost thresholds in Order No. 1920 and that nine of the 14 withdrew before a feasibility study was issued. Additionally, PJM argues that, of the remaining five, two were ultimately responsible for network upgrades of less than $30 million, thus leaving only three interconnection requests potentially withdrawing due to the cost of network upgrades.[1342] PJM argues that this data suggesting a withdrawal rate of less than one half percent in a large sample indicates insignificant correlation between network upgrade costs, voltage level, and business decisions to withdraw.[1343]

515. PJM further argues that, on the other hand, over the past six years, several dozen generation projects that executed interconnection agreements had associated network upgrades of less than $5 million but nonetheless terminated their interconnection agreements. Thus, PJM argues that factors other than sticker shock are common reasons for delay or failure to advance.[1344] PJM argues that the Commission disregarded this evidence and relied on studies in MISO and SPP to justify a one-size-fits-all approach,

[1341] PJM Rehearing Request at 31.

[1342] *Id.*

[1343] *Id.*

[1344] PJM Rehearing Request at 32.

and it argues that this decision was arbitrary and capricious.[1345] NRECA argues that if the Commission believes that its existing generator interconnection polices are unjust and unreasonable and impose barriers to generation development, it should develop the appropriate evidentiary record, make the required findings, and direct a just and reasonable replacement policy.[1346]

### 3. Commission Determination

516. We continue to find that this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.[1347] While SERTP Sponsors, Large Public Power, and Industrial Customers argue that this reform is premature in light of Order No. 2023, we find that the scope of the Order No. 1920 coordination reform operates independently of, and is more limited than, the Order No. 2023 reforms. Order No. 2023 adopts reforms to the generator interconnection process through changes to the *pro forma* generation interconnection procedures and agreements. By comparison, Order No. 1920 adopts no changes to the generator interconnection process and instead implements the coordination reform through changes to the transmission planning process and the *pro forma* OATT.

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[1345] *Id.* at 32 (citing 5 U.S.C. 706(2); 16 U.S.C. § 825l(b); *S.C. Pub. Serv. Auth.*, 762 F.3d at 66-67; *TAPS*, 225 F.3d at 687; *Env't Def. Fund*, 2 F.4th 953).

[1346] NRECA Rehearing Request at 48-49.

[1347] Order No. 1920, 187 FERC ¶ 61,068 at P 1106.

517. Additionally, the purpose of the coordination reform in Order No. 1920 is to address a specific problem—insufficient coordination between the existing generator interconnection processes and regional transmission planning and cost allocation processes regarding interconnection-related transmission needs that are repeatedly identified in the generator interconnection process.[1348] Order No. 1920 recognizes the generator interconnection process is unlikely to result in the construction of transmission facilities that resolve such interconnection-related transmission needs because of the rate of withdrawal from the interconnection queue, due at least in part to interconnection customers' cost responsibility for expensive interconnection-related network upgrades.[1349] While Order No. 2023 aims to fix inefficiencies in the generator interconnection process, it does not direct any reforms regarding specific interconnection-related network upgrades that are unlikely to be developed.

518. The Commission reasonably concluded that reforms regarding these types of network upgrades are better addressed through improvement of coordination between the generator interconnection and regional transmission planning processes. The purpose of the Order No. 1920 coordination reform is to (1) require evaluation of regional transmission facilities that address certain (i.e., that qualify under the criteria established in Order No. 1920) interconnection-related transmission needs associated with specific interconnection-related network upgrades in existing Order No. 1000 regional

[1348] *Id.* P 1100.

[1349] *See id.* P 1108.

transmission planning and cost allocation processes to determine whether to select such facilities in the regional transmission plan for purposes of cost allocation, and (2) determine whether such facilities may address other regional transmission needs more efficiently or cost-effectively. For a limited set of interconnection-related transmission needs, this reform will allow transmission providers to identify, evaluate, and select the more efficient or cost-effective regional transmission solution independent of the success or failure of a particular interconnection request in the generator interconnection process. Additionally, if this requirement is triggered (i.e., because interconnection-related network upgrades meet all of the established qualifying criteria), that is an indication of the continued existence of the concerns described in Order No. 1920, namely a barrier to entry in locations that, absent sticker shock, are "otherwise desirable for generators to locate."[1350] Moreover, it may be that eventually, as a result of Order No. 2023, fewer withdrawals from the generator interconnection queue occur and that this provision is triggered less often. Further, there may be fewer instances of this requirement as the Order No. 1920 Long-Term Regional Transmission Planning process proactively addresses transmission needs related to generation additions on a forward-looking basis. These developments would not, however, address the present concerns that necessitate this coordination requirement. Given the low administrative burden associated with this reform,[1351] we conclude that its potential benefits outweigh the costs.

[1350] *Id.* P 1103.

[1351] *See id.* P 1113.

519. We disagree with PJM's claim that the Commission does not provide substantial evidence to demonstrate that existing Order No. 1000 regional transmission planning and cost allocation processes do not adequately address interconnection-related transmission needs associated with withdrawn interconnection requests. PJM's claim is unpersuasive because, as explained above, the Commission has sufficiently demonstrated the need for reform.

520. The Commission in Order No. 1920 also explained why it is appropriate to establish the coordination requirement in existing Order No. 1000 regional transmission planning and cost allocation processes, stating that:

> Evaluation of interconnection-related transmission needs in the existing Order No. 1000 regional transmission planning and cost allocation processes is most appropriate because such evaluation would occur at shorter intervals and would likely result in more expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.[1352]

521. Further, courts have recognized the Commission can rely on general findings of systemic conditions to impose an industry-wide remedy under FPA section 206.[1353] The Commission found that there was substantial evidence to conclude that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not adequately consider certain

[1352] *Id.* P 1126.

[1353] *See TAPS*, 225 F.3d at 687-88 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (citing *Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d at 37).

interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been resolved due to the withdrawal of the underlying interconnection request(s).[1354]

522. We also are not persuaded by the evidence that PJM presented in this proceeding, which it argues demonstrates that only a small fraction of network upgrades that are the subject of its analysis would meet the voltage and cost thresholds established by Order No. 1920. We do not reach the same conclusions as PJM for multiple reasons. To begin, PJM's evidence pertains only to the Dominion zone in PJM from 2014 to 2020 and is not necessarily reflective of circumstances across the region, or nationwide, or over different time periods. Further, in Order No. 1920, the Commission cited to evidence from the record to support the conclusion that, in recent years, sticker shock over an interconnection customer's assigned network upgrade costs is often the deciding factor that leads to that interconnection customer's withdrawal of its interconnection request.[1355] For instance, the Commission cited analysis from a report showing that between January 2016 and July 2020, 245 generation projects in advanced stages in the MISO generator interconnection process withdrew from the queue, with the project developers citing high

[1354] *Id.* PP 1100-05.

[1355] *See*, *e.g.*, *id.* P 1101 (citing *See* ACORE ANOPR Comments at 12; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and Intermountain Initial Comments at 14; *see also Improvements to Generator Interconnection Procs. & Agreements,* Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at 41, *order on reh'g,* Order No. 2023-A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199, at P 14 (2024).

interconnection-related network upgrade costs as the primary reason for their withdrawal.[1356]

523. We also disagree with PJM's interpretation of its data, namely the claim that there is no need for reform because the data shows that the number of withdrawals due to sticker shock is small. PJM's reasoning suggests that the Commission found that sticker shock is only ever a deciding factor for an interconnection request's withdrawal if the withdrawn interconnection request was allocated interconnection-related network upgrade costs of $30 million or more or has a voltage of at least 200 kV (i.e., the cost and voltage thresholds established by Order No. 1920 to limit the applicability of this new requirement). However, the Commission did not suggest that interconnection-related network upgrades below this cost threshold or below the 200 kV voltage threshold do not cause sticker shock. Instead, the established qualifying criteria are intended to strike a reasonable balance between precision and workability.[1357] To accomplish this workability, the Commission adopted requirements that do not require evaluation in the existing Order No. 1000 regional transmission planning and cost allocation processes of all interconnection-related transmission needs that were not addressed because the corresponding interconnection request withdrew in part or entirely due to sticker shock.

[1356] *Id.* (citing Jay Caspary et al., ACEG, Disconnected: The Need for a New Generator Interconnection Policy, 14 (2021)), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-aNew-Generator-Interconnection-Policy-1.pdf (ACEG 2021 Interconnection Report) at 17.

[1357] *See id.* P 1147.

Instead, as the Commission stated in Order No. 1920, the established criteria are necessary to limit the scope of the requirement to interconnection-related transmission needs associated with high-cost interconnection-related network upgrades "that are likely to persist, . . . not unique to a single interconnection request, and . . . that have the potential to provide more widespread benefits to transmission customers."[1358] We again find that this targeted approach and criteria are "broad enough to capture interconnection-related network upgrades that are likely to produce benefits beyond the interconnection customer" while retaining flexibility for transmission providers.[1359]

524. In response to NRECA, we note that the focus of Order No. 1920 is to remedy deficiencies in the regional transmission planning and cost allocation requirements and not the generator interconnection process. Nonetheless, we reiterate the findings in Order No. 1920 that the repeated identification of interconnection-related network upgrades in the generator interconnection process is indicative of a "barrier to accessing the transmission system and [establishes] a known interconnection-related transmission need … [that] can hinder the timely development of new generation, thereby stifling competition in wholesale electricity markets and limiting access to lower-cost generation" and that by "failing to consider such interconnection-related transmission

[1358] *Id.* P 1148.

[1359] *Id.* P 1149.

needs, the regional transmission planning process is unable to identify the more efficient or cost-effective regional transmission solutions."[1360]

### B. Qualifying Criteria

#### 1. Order No. 1920 Requirements

525. In Order No. 1920, the Commission required transmission providers to evaluate for selection in their existing Order No 1000 regional transmission planning processes regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process by meeting four qualifying criteria. Specifically, the Commission required transmission providers to evaluate interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions); (2) an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million; (3) such interconnection-related network upgrade(s) have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the network

[1360] *Id.* P 1103.

upgrade(s) has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.[1361]

526. The Commission found it necessary to establish these criteria to limit the scope of the requirement to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers.[1362] The Commission found that these criteria strike a reasonable balance between precision and workability, and that each of the four criteria is necessary to identify the appropriate set of interconnection-related transmission needs.[1363] The Commission further found that the purpose of the criteria established in Order No. 1920 is to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration in the existing Order No. 1000 regional transmission planning and cost allocation processes.[1364]

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[1361] *Id.* P 1145.

[1362] *Id.* P 1146.

[1363] *Id.* PP 1146-1147.

[1364] *Id.* P 1150.

527. As relevant here, the Commission proposed in the NOPR that part of the criteria regarding interconnection-related transmission needs is met where an interconnection-related network upgrade identified to meet interconnection-related transmission needs in the generator interconnection process has a voltage of at least 200 kV and/or an estimated cost of at least $30 million.[1365] In Order No. 1920, the Commission found it necessary and just and reasonable to modify the NOPR proposal such that any interconnection-related network upgrade identified to meet that interconnection-related transmission need must have a voltage of at least 200 kV *and* an estimated cost of at least $30 million (the cost-and-voltage criterion).[1366] The Commission found it necessary to establish a cost threshold that is stringent enough to capture those interconnection-related network upgrades that are likely to have caused the underlying interconnection requests to withdraw and a voltage threshold that is high enough that any regional transmission facility evaluated to address the underlying interconnection-related transmission need(s) is likely to produce benefits that extend beyond the interconnection customer.[1367] The Commission provided additional support for the voltage threshold in stating that the Commission has also previously found, and the record demonstrates, that higher-voltage

[1365] *Id.* P 1130.

[1366] *Id.* PP 1145, 1150-1151.

[1367] *Id.* P 1151.

transmission facilities are more likely to provide widespread benefits to transmission customers.[1368]

528. The Commission stated that requiring an interconnection-related network upgrade identified to meet an interconnection-related transmission need to satisfy both the cost and voltage criteria will prevent transmission providers from evaluating interconnection-related transmission needs associated with interconnection-related network upgrades that are less likely to provide more widespread benefits to transmission customers.[1369] The Commission found that requiring both the cost threshold and the voltage threshold be met better limits the scope of the reform compared to the NOPR proposal and thus the reform is more likely to produce a smaller and more practicable set of interconnection-related needs that transmission providers must evaluate in their existing Order No. 1000 regional transmission planning processes.[1370] The Commission also stated that the change to require that both the cost threshold and the voltage threshold be met addresses commenters' concerns that relying on only one threshold would identify interconnection-related network upgrades that are less likely to provide more widespread benefits to transmission customers.[1371]

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[1368] *Id.* P 1146, n. 2433.

[1369] *Id.* P 1152.

[1370] *Id.* P 1146; *id.* P 1151; *id.* P 1153.

[1371] *Id.* P 1153 (citing Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; US DOE Initial Comments at 28.).

529. In Order No. 1920, the Commission also established as another qualifying criterion that transmission providers must have identified interconnection-related network upgrades in interconnection studies to address the same interconnection-related transmission need in at least two interconnection queue cycles during the preceding five years (repeat identification criterion).[1372] Like for the cost-and-voltage criterion, the Commission stated that the repeat identification criterion provides an important limit on the extent to which evaluation of regional transmission facilities to address interconnection-related transmission needs is required.[1373] The Commission further explained that repeat identification indicates that the constraint that the interconnection-related network upgrades were identified to address is not unique to a single interconnection request at a single point in time and that the interconnection-related transmission need is likely to persist.[1374] The Commission explained that, if it did not limit the requirements in this way, the burden of evaluation would be greater because transmission providers could have to evaluate more interconnection-related transmission needs.[1375]

530. The Commission also clarified the timing of the requirement that transmission providers have identified interconnection-related network upgrades in interconnection

[1372] *Id.* P 1145.

[1373] *Id.* P 1150.

[1374] *Id.* PP 1150, 1158.

[1375] *Id.* P 1150.

studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years.[1376] The Commission explained that this five-year period means looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions.[1377] Separately, the Commission explained that transmission providers must evaluate an interconnection-related transmission need that has been previously identified multiple times within the five years prior to the effective date of the Commission-accepted tariff provisions but never been resolved due to the withdrawal of the underlying interconnection request(s).[1378] The Commission also clarified that if there are no "queue cycles" in the preceding five-year period because the transmission provider uses a first-come, first-served serial interconnection process, then this criterion will be met if the interconnection-related transmission need is identified in at least two individual interconnection studies during the preceding five-year period for interconnection customers that subsequently withdrew from the interconnection queue.[1379] Finally, the Commission stated that evaluation for selection of regional

[1376] *Id.* PP 1145, 1158-1160.

[1377] *Id.* P 1145.

[1378] *Id.* P 1159.

[1379] We note that this accommodation will eventually become moot because transmission provides that do not already do so must transition to a cluster study rather than a serial process pursuant to the requirements of Order No. 2023. *See* Order No.

transmission facilities that address certain (i.e., that qualify under the criteria established in Order No. 1920) identified interconnection-related transmission needs must occur in the first Order No. 1000 regional transmission planning and cost allocation processes cycle that commences after the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions.[1380]

531. For both the cost-and-voltage criterion and the repeat identification criterion, the Commission disagreed with commenters that argued for the adoption of different criteria or for the elimination of one or both criteria and found that requiring both criteria is just and reasonable.[1381]

### 2. Requests for Rehearing and Clarification

532. Clean Energy Associations contend that the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making by adopting the cost-and-voltage criterion and repeat identification criterion.[1382] Clean Energy Associations ask that the Commission, at a minimum, only require either a voltage criterion *or* cost criterion, such that the eligibility threshold is met if an interconnection-related network upgrade has a voltage of at least 200 kV *or* an estimated cost of at least $30 million.[1383]

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2023, 184 FERC ¶ 61,054 at P 223.

[1380] Order No. 1920, 187 FERC ¶ 61,068 at P 1159.

[1381] *Id.* P 1150 (citations omitted).

[1382] Clean Energy Associations Rehearing Request at 13-22.

[1383] *Id.* at 21-22.

Clean Energy Associations also request that the Commission grant rehearing to change the repeat identification criterion, such that the criterion is met if an interconnection-related network upgrade was identified in at least one interconnection queue cycle.[1384] Separately, Clean Energy Associations ask the Commission to clarify that the time period transmission providers must use to identify interconnection-related network upgrades for inclusion in the initial regional transmission planning cycle exceeds five years, or alternatively, grant rehearing to require so.[1385]

533. As to the cost-and-voltage criterion, Clean Energy Associations contend that the Commission acted arbitrarily and capriciously because it failed to explain how interconnection-related network upgrades that satisfy both the voltage threshold and cost threshold (as required in Order No. 1920) are more likely to provide widespread benefits to customers compared to interconnection-related network upgrades that meet only the voltage threshold or only the cost threshold (as proposed in the NOPR).[1386] Clean Energy Associations claim that the Commission ignored record evidence and adopted eligibility criteria that arbitrarily exclude lower voltage facilities that cost more than $30 million from consideration in regional transmission planning processes regardless of the degree to which those interconnection-related network upgrades benefit transmission

[1384] *Id.*

[1385] *Id.* at 22-26.

[1386] *Id.* at 13-14.

customers.[1387] Clean Energy Associations assert that the Commission ignored evidence that requiring both the cost threshold and the voltage threshold to be met is even more harmful in certain parts of the country.[1388]

534. Clean Energy Associations also claim that the Commission mischaracterized certain comments opposing the imposition of a requirement to meet both the cost threshold and the voltage threshold as comments favoring "elimination of one or both criteria" when many of such comments actually support what Clean Energy Associations refer to as the "flexibility" in the NOPR that only required an interconnection-related network upgrade to satisfy one of the thresholds to be eligible for evaluation.[1389] Clean Energy Associations further argue that the record shows that the NOPR's "flexibility" is more likely to identify interconnection-related transmission needs that warrant evaluation compared to the requirements in Order No. 1920, because Order No. 1920's requirement to meet both the cost threshold and the voltage threshold unduly limits the universe of transmission solutions in a manner that jeopardizes transmission providers' ability to evaluate transmission solutions that might be more efficient or cost-effective than other

[1387] *Id.* at 15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1137 (referencing comments of Pattern Energy, Pine Gate, and Shell)).

[1388] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1140 (referencing comments of PJM)).

[1389] *Id.* at 16 (citing Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32; Interwest Initial Comments at 3, 11).

options.[1390] Clean Energy Associations claim that the Commission did not directly address the record evidence and arguments on this issue, which renders this aspect of the Order No. 1920 arbitrary and capricious.[1391]

535. On the repeat identification criterion, Clean Energy Associations contend that this criterion is arbitrary and inconsistent with Order No. 1920's goal of removing barriers to entry, increasing competition, and promoting more efficient or cost-effective solutions to interconnection-related transmission needs.[1392] Clean Energy Associations believe that the repeat identification criterion will render Order No. 1920's reforms to coordinate the regional transmission planning and generator interconnection processes ineffective for several reasons that the Commission failed to address, including the Commission's shift to cluster-based studies, the self-defeating nature of the repeat identification criterion, and the adverse effects of the repeat identification criterion in conjunction with the cost-and-voltage criterion.[1393] Clean Energy Associations claim that the Commission also ignored substantial record evidence and arguments relevant to the eligibility criteria and that the Commission's stated rationale for adopting its unduly restrictive criteria "does not hold water."[1394]

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[1390] *Id.* at 16-17.

[1391] *Id.* at 17.

[1392] *Id.* at 18.

[1393] *Id.* at 18-21.

[1394] *Id.* at 20-21 (quoting *e.g.*, Interwest Initial Comments at 11 ("the NOPR imposes so many procedural hurdles that . . . it could not be expected to produce results .

536. Clean Energy Associations also request clarification on two issues related to the time period for the repeat identification criterion. First, Clean Energy Associations request that the Commission clarify that, for each transmission provider's initial regional transmission planning cycle under an Order No. 1920-compliant tariff, the review window for identifying interconnection-related network upgrades that are required to be considered as interconnection-related transmission needs may span more than five years in duration.[1395] As an example, Clean Energy Associations state that:

> if a transmission provider's Order No. 1920-compliant tariff takes effect on August 1, 2025, [and] the first regional transmission planning cycle in which interconnection-related transmission needs must be considered commences on August 1, 2027, and the date on which the transmission provider will identify the transmission solutions to be evaluated in that planning cycle is April 1, 2028, then the transmission provider must include for evaluation any network upgrades that were identified in interconnection cycles between August 1, 2020 (i.e., five years before the effective date) and April 1, 2028 (i.e., the date on which transmission solutions are identified for inclusion in the transmission planning process) and that meet the eligibility criteria. In that hypothetical example, the total time-period over which network upgrades could be identified for evaluation as interconnection-related transmission needs is seven years and nine months.[1396]

537. Second, noting the requirement in Order No. 1920, Clean Energy Associations request that the Commission clarify that any eligible interconnection-related network

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. . requiring that the same interconnection upgrades be identified twice . . . is simply impractical")).

[1395] *Id.* at 23-24.

[1396] *Id.* at 24.

upgrade that is identified in any two interconnection cycles within the review window—even if both occurrences took place in the five years prior to the effective date—must be evaluated in the transmission providers' initial Order No. 1000 regional transmission planning cycle following the effective date of its Order No. 1920 compliance filing.[1397] Clean Energy Associations argue that there is no reason why the "later in time withdrawn interconnection request" must occur after the "effective date of the Commission-accepted tariff provisions" rather than at any point during the relevant lookback period. Clean Energy Associations claim that, absent the requested clarification, the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making by failing to clearly identify the time period at which transmission providers must look to implement this reform.[1398]

### 3. Commission Determination

538. We disagree with Clean Energy Associations' requests for rehearing and decline to revise the cost-and-voltage criterion and the repeat identification criterion. We continue to find that it is necessary to limit the scope of the requirement to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities

[1397] *Id.* at 25 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1145 (establishing the requirement that the time period is "the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions)")).

[1398] *Id.* at 3, 25.

that have the potential to provide more widespread benefits to transmission customers.[1399] We reiterate the Commission's stated purpose of this reform, which is to address the narrow issue of interconnection-related transmission needs being repeatedly identified yet continuing to go unresolved through the generator interconnection process, even though more efficient or cost-effective regional transmission solutions could be achieved if such needs were evaluated through the regional transmission planning and cost allocation process.[1400]

539. We disagree with Clean Energy Associations' argument that the Commission acted arbitrarily and capriciously in adopting the requirement to meet both the cost threshold and the voltage threshold. In Order No. 1920, the Commission explained how the cost threshold is intended to capture interconnection-related network upgrades that cause underlying interconnection requests to withdraw (i.e., are likely to persist), and the voltage threshold is intended to capture interconnection-related transmission needs that are likely to produce more widespread benefits.[1401] These explanations for requiring that previously identified interconnection-related network upgrades meet both of these thresholds for an interconnection-related transmission need to satisfy the cost-and-voltage criterion are consistent with the Commission's stated purpose and the necessary scope of this reform. Namely, the cost threshold identifies interconnection-related transmission

[1399] Order No. 1920, 187 FERC ¶ 61,068 at P 1146.

[1400] *Id.* P 1112.

[1401] *Id.* P 1151.

needs associated with prohibitive interconnection-related network upgrade costs that contribute to a barrier to accessing the transmission system, and the voltage threshold identifies interconnection-related transmission needs with the potential for transmission benefits that extend beyond the interconnection customer.[1402] We also disagree with Clean Energy Associations' claim that the Commission ignored record evidence on this issue.[1403] As stated above, the Commission adopted this reform and the associated qualifying criteria to address a narrow issue with limited scope, not to address an expansive set of interconnection-related transmission needs as requested by some commenters in response to the NOPR.

540. We disagree with Clean Energy Associations that providing for the "flexibility" of meeting either the cost threshold or the voltage threshold is more consistent with Order No. 1920's objectives. Allowing such flexibility places Clean Energy Associations' preferred policy outcome in place of the need for reform articulated by the Commission.[1404] The Commission in Order No. 1920 explained that the coordination reform is not intended to create an expansive set of interconnection-related transmission needs that transmission providers must evaluate in the regional transmission planning and cost allocation processes. Instead, this reform is intended to identify a limited set of

[1402] *Id.* PP 1103-1104.

[1403] Clean Energy Associations Rehearing Request at 15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1137 (referencing comments of Pattern Energy, Pine Gate, and Shell); Order No. 1920, 187 FERC ¶ 61,068 at P 1140 (referencing comments of PJM)).

[1404] Order No. 1920, 187 FERC ¶ 61,068 at PP 1106-1121.

interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. We believe that requiring transmission providers to consider a more limited set of interconnection-related transmission needs through their existing regional transmission planning and cost allocation processes is warranted because a more expansive set could include transmission needs associated with expensive but relatively low voltage interconnection-related network upgrades (which are less likely to provide widespread benefits to transmission customers compared to higher voltage transmission facilities) and transmission needs associated with high voltage but relatively inexpensive network upgrades (which are less likely to remain unbuilt by interconnection customers).

541. As explained in Order No. 1920, in the context of the repeat identification criterion, we are also concerned that relaxing the qualifying criteria would create greater burdens on transmission providers by increasing the number of interconnection-related transmission needs that transmission providers must evaluate in their Order No. 1000 regional transmission planning and cost allocation processes without widespread benefits to transmission customers.[1405] Additionally, the repeat identification criterion is meant to refine the evaluation to apply to more actionable and valuable interconnection-related transmission needs that may be better suited for evaluation and development in the existing Order No. 1000 regional transmission planning and cost allocation processes.

[1405] *Id.* P 1150.

542. We disagree with Clean Energy Associations' claim that the requirement to meet both the cost threshold and the voltage threshold unduly limits the universe of transmission solutions in a manner that jeopardizes transmission providers' ability to evaluate transmission solutions that might be more efficient or cost-effective than other options. Clean Energy Associations conflate transmission needs and transmission solutions to address those needs. The purpose of the qualifying criteria adopted in Order No. 1920 is to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration.[1406] Contrary to Clean Energy Associations' claim, the qualifying criteria in Order No. 1920 do not limit the transmission solutions that transmission providers may evaluate to address the identified interconnection-related transmission needs. Instead, the qualifying criteria in Order No. 1920 limit the set of interconnection-related transmission needs that transmission providers must evaluate. We believe requiring transmission providers to evaluate this subset of transmission needs is justified because interconnection-related transmission needs that satisfy both the cost threshold and the voltage threshold can be solved with transmission facilities that are more likely to provide widespread benefits to the transmission system and be selected in the regional transmission for purposes of cost allocation as the more efficient and cost-effective transmission solution, compared to interconnection-related transmission needs that satisfy only the cost threshold, or only the voltage threshold.

[1406] *Id.*

543. We also disagree with Clean Energy Associations' claim that the Commission's decision to adopt the repeat identification criterion is arbitrary and inconsistent with the goals of Order No 1920. Clean Energy Associations' request for rehearing effectively asks the Commission to eliminate the repeat identification criterion to require the evaluation of more interconnection-related transmission needs in regional transmission planning processes, an argument that some commenters made in response to the NOPR and with which the Commission disagreed in Order No. 1920.[1407] The Commission explained in Order No. 1920 that the purpose of this criterion is to indicate that an interconnection-related transmission need is likely to persist and to limit the extent to which evaluation of regional transmission facilities to address interconnection-related transmission needs is required.[1408]

544. In response to Clean Energy Associations' request to clarify the timing requirements, and as more fully described below, we clarify that the time period that transmission providers use to identify interconnection-related transmission needs for potential consideration during any Order No. 1000 regional transmission planning and cost allocation process cycle will be longer than five calendar years. Additionally, we modify the requirements adopted in Order No. 1920 to resolve ambiguity about timing. We find that these modifications are necessary for transmission providers to determine precisely when the coordination requirements are triggered. Specifically, we modify

[1407] *Id.*

[1408] *Id.* PP 1150, 1158.

criterion (1), the repeat identification criterion, and criterion (3), which specifies the maximum time period between withdrawals of interconnection requests associated with the same interconnection-related transmission need (the double withdrawal criterion). We also adopt a new criterion (5), which specifies the timing for identifying withdrawn interconnection requests associated with the same interconnection-related transmission need in the initial and successive Order No. 1000 regional transmission planning and cost allocation cycles (the withdrawal window criterion). The withdrawal window criterion clarifies the intent of the repeat identification criterion in Order No. 1920.[1409]

545. In particular, we modify the repeat identification criterion to read (with additions in bold and italicized and deletions struck through):

> (1) Transmission Providers in the transmission planning region have identified the relevant interconnection-related transmission need in interconnection studies in at least two interconnection queue cycles ***(or in at least two individual interconnection studies for Transmission Providers that use a first-come, first-served serial generator interconnection process)***~~during the preceding five years (looking back from the effective date of the accepted tariff provisions proposed to comply with this reform in Order No. 1920, and the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions)~~;

We also modify the double withdrawal criterion in Attachment K to read (with additions in bold and italicized and deletions struck through):

> (3) ~~the interconnection-related Network Upgrade identified through the generator interconnection process to meet the~~

[1409] We also make a minor modification to criterion (4) to account for the fact that we are adopting an additional qualifying criterion. All the revisions detailed below are reflected in the Attachment K Appendix to this order.

> ~~relevant interconnection-related transmission need is not currently planned to be developed because~~ the interconnection request~~(s)~~ that led to the identification of the interconnection-related transmission need ***in two or more interconnection queue cycles (or two individual interconnection studies if the Transmission Provider uses a first-come, first-served serial generator interconnection process) have*** ~~has~~ been withdrawn ***and no more than five calendar years have passed between the date of an earlier interconnection request withdrawal and the date of a later interconnection request withdrawal***; ~~and~~

We make a slight modification to criterion (4) so that it reads (with additions in bold and italicized and deletions struck through):

> the Transmission Providers have not identified a different interconnection-related Network Upgrade to meet the relevant interconnection-related transmission need in an executed Generator Interconnection Agreement or in a Generator Interconnection Agreement that the interconnection customer requested that the Transmission Provider file unexecuted with the Commission~~.~~***; and***

We also add a new criterion (5), the withdrawal window criterion, as follows (with additions in bold and italicized):

> ***(5) The interconnection request withdrawals associated with the repeatedly identified interconnection-related transmission need occurred no earlier than seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. The initial evaluation should occur in the first Order No. 1000 regional transmission planning and cost allocation cycle to occur after the effective date of the tariff revisions implementing this reform. The transmission provider need not evaluate an interconnection-related transmission need that has been evaluated in a previous Order No. 1000 regional transmission planning and cost allocation cycle.***

546. We make these modifications to resolve confusion about the timing requirements for this reform. The Commission's *pro forma* generator interconnection procedures require an annual cluster request window for interconnection customers to submit interconnection requests.[1410] Over the span of the interconnection cycle, the transmission provider studies the interconnection requests and provides more refined interconnection study results.[1411] The requirements of this reform provide an opportunity for transmission providers to evaluate interconnection-related transmission needs associated with repeatedly identified interconnection-related network upgrades that are not developed through the generator interconnection process because the interconnection requests associated with interconnection-related network upgrade withdraw from the interconnection queue.[1412]

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[1410] *See pro forma* LGIP § 3.4.1. As Order No. 1920 recognizes, however, for a transmission provider that operates a serial process and studies interconnection requests on a first-come, first served basis, the criterion will be met if the interconnection-related transmission need is identified in at least two individual interconnection studies during the preceding five-year period for interconnection customers that subsequently withdrew from the interconnection queue. Order No. 1920, 187 FERC ¶ 61,068 at P 1160. As noted above, however, this intricacy will be rendered moot as transmission providers with serial queues come into compliance with Order No. 2023, which requires them to transition to a cluster study process. *Supra* P 530 n.1380; *see* Order No. 2023, 184 FERC ¶ 61,054 at P 223.

[1411] *See*, *e.g.*, *pro forma* §§ LGIP 3.1.1 (Study Deposits), 7 (Cluster Study), 8 (Interconnection Facilities Study), 9 (Affected Systems Study), 10 (Option Interconnection Study).

[1412] Order No. 1920, 187 FERC ¶ 61,068 at P 1108 (because "the high cost of interconnection is increasing the rate at which generators withdraw from the interconnection queue. . . . interconnection customers are unlikely to resolve these interconnection-related transmission needs through the generator interconnection

547. The modifications that we make here clarify that a transmission provider need not evaluate an interconnection-related transmission need if more than five calendar years separate the withdrawal of the earlier and later interconnection requests associated with an interconnection-related transmission need (the double withdrawal criterion). Additionally, the withdrawal window criterion makes clear that a transmission provider need only evaluate an interconnection-related transmission need in its Order No. 1000 regional transmission planning and cost allocation cycle if the withdrawal of the interconnection requests associated with the repeatedly identified interconnection-related transmission need occurred within the seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle.

548. We find that seven years is an appropriate period because it accounts for the time between withdrawn interconnection requests associated with otherwise eligible interconnection-related transmission needs (at most five years, as specified in the double withdrawal criterion) and accounts for the fact that the timing of generator interconnection queue cluster cycles likely does not coincide with the Order No. 1000 regional transmission planning and cost allocation cycle. Additionally, this seven-year period also accounts for the potential lag between the effective date of the Commission-approved tariff revisions and the initial Order No. 1000 regional transmission planning and cost allocation cycle (for the initial Order No. 1000 cycle) or the time between Order No. 1000 cycles (for subsequent Order No. 1000 cycles). Consequently, by establishing

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process.")

a seven-year withdrawal window period, we avoid the possibility of otherwise qualifying interconnection-related transmission needs being ineligible for evaluation in an Order No. 1000 regional transmission planning and cost allocation cycle due to an inadequate withdrawal window period that does not account for lags between processes.

549. We also believe this seven-year period for the withdrawal window is simpler to calculate than the language that the Commission previously adopted for the repeat identification criterion in Order No. 1920 (before the modifications described here). The reason is that transmission providers will only need to look back seven calendar years from a single date (the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle). Without the modifications adopted here, the first qualifying criterion of the repeat identification criterion in Order No. 1920 established several look-back periods in reference to multiple dates.[1413]

550. As a result of the modifications above, there is no need to distinguish between the initial Order No. 1000 regional transmission planning and cost allocation cycle and subsequent No. 1000 regional transmission planning and cost allocation cycles. Thus, for the initial implementation of this reform, the transmission provider need only determine if the qualifying criteria are satisfied for the period beginning seven calendar years before

[1413] *Id.* P 1145 ("(1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions)").

the initial Order No. 1000 regional transmission planning and cost allocation cycle commencement date. We acknowledge that, in implementation, this start date is likely to be earlier than the start date established in Order No. 1920.[1414] As a result, transmission providers may need to consider one or two additional years of withdrawn interconnection requests during the initial Order No. 1000 regional transmission planning and cost allocation cycle. However, we believe this departure from Order No. 1920 is necessary to resolve the ambiguity raised on rehearing and to establish clear qualifying criteria for transmission providers to implement going forward.

551. In addition, the withdrawal window criterion makes clear that a transmission provider need not evaluate an interconnection-related need that meets all the qualifying criteria if it has already evaluated that interconnection-related transmission need in an Order No. 1000 regional transmission planning and cost allocation cycle. This modification is necessary to prevent transmission providers from having to evaluate an interconnection-related transmission need in more than one Order No. 1000 regional transmission planning and cost allocation cycle.

552. Consistent with the adoption of the withdrawal window criterion, we clarify for Clean Energy Associations that the time period that transmission providers use to identify interconnection withdrawals is longer than five calendar years. In particular, the withdrawal window criterion requires the transmission provider to determine if the interconnection request withdrawals associated with the repeatedly identified

[1414] *Id.* P 1159.

interconnection-related transmission need occur within seven calendar years prior to the commencement of the relevant Order No. 1000 regional transmission planning and cost allocation cycle.

553. To explain how this would work, consider the following hypothetical and assume that the voltage-and-cost threshold criterion is satisfied:

- Transmission provider identifies interconnection-related transmission need A as necessary to interconnect interconnection request A in interconnection cluster cycle 1.
- Interconnection request A withdraws from interconnection cluster cycle 1 on August 1, 2035.
- In interconnection cluster cycle 2, transmission provider identifies interconnection-related transmission need A as necessary to interconnect interconnection request B.
- Interconnection request B withdraws from interconnection cluster cycle 2 on or before August 1, 2040.
- The first Order No. 1000 regional transmission planning and cost allocation cycle following the withdrawal of interconnection request B commences on January 1, 2042.

In this example, the repeat identification criterion would be satisfied because the same interconnection-related transmission need was identified for interconnection request A and interconnection request B in interconnection cluster cycle 1 and interconnection cluster cycle 2, respectively. The double withdrawal criterion would be satisfied because

no more than five calendar years have passed between the withdrawal of interconnection request A and interconnection request B. The withdrawal window criterion would be satisfied because the withdrawals of interconnection request A and interconnection request B occurred within seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. Consequently, the transmission provider would be required to evaluate interconnection-related transmission need A in the Order No. 1000 regional transmission planning and cost allocation cycle that commences on January 1, 2042.

554. We turn now back to Clean Energy Associations' first clarification request and explain these requirements using the dates provided in Clean Energy Associations' example, where the relevant tariff revisions would become effective August 1, 2025, the initial Order No. 1000 regional transmission planning and cost allocation cycle would commence on August 1, 2027, and the transmission solutions to be evaluated will be identified on April 1, 2028.

555. We clarify that the April 1, 2028 date would not be relevant for determining whether a transmission provider must evaluate an interconnection-related transmission need. The relevant dates are the interconnection request withdrawal dates and the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. In Clean Energy Associations' example, the transmission provider would identify interconnection request withdrawals between August 1, 2020 (seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle provided in this example) and August 1,

2027 (the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle provided in this example). Of those withdrawals, the repeat identification criterion will be satisfied if no more than five calendar years elapsed between the earlier and later interconnection request withdrawal dates for interconnection requests associated with the same repeatedly identified interconnection-related transmission need. Thus, withdrawals of interconnection requests with the earlier occurring on August 1, 2020 and the later occurring August 1, 2025 would satisfy the double withdrawal criterion. The same is true for withdrawals of interconnection requests with the earlier occurring on August 1, 2022 and the later occurring August 1, 2027. The double withdrawal criterion would not be satisfied, however, if the first withdrawal occurred on August 1, 2020 and the later occurred on August 2, 2025 because more than five calendar years occur between the earlier and later interconnection request withdrawals.

556. Additionally, in response to Clean Energy Associations' second request for clarification, we note that the modifications to the repeat identification criterion adopted here delete the Attachment K language adopted in Order No. 1920 that created confusion.[1415] Consistent with the modifications adopted here, we clarify that the double withdrawal criterion requires that no more than five calendar years occur between the earlier and later interconnection request withdrawals and that the withdrawal window criterion makes clear that transmission providers need not evaluate an interconnection-

[1415] *See id.* P 1145.

related transmission need if the relevant interconnection request withdrawals do not occur within the seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle.

### C. Cost Allocation

#### 1. Order No. 1920 Requirements

557. In Order No. 1920, the Commission adopted new coordination requirements to require that transmission providers evaluate regional transmission facilities that address certain interconnection-related transmission needs identified by this reform in the existing Order No. 1000 regional transmission planning and cost allocation processes.[1416] The Commission also stated that requests to modify existing cost allocation criteria were outside the scope of the proceeding.[1417] Additionally, the Commission stated that transmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply. Further, Order No. 1920 did not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process.[1418] The Commission went on to explain that, to the extent that transmission providers wish to

[1416] *Id.* P 1111.

[1417] *Id.* P 1112.

[1418] *Id.* P 1117.

propose changes to their Order No. 1000 regional cost allocation method(s) because of this new requirement, they would need to do so in separate FPA section 205 filings rather than on compliance with Order No. 1920.[1419]

### 2. Requests for Rehearing and Clarification

558. Retail Regulators, Ohio Consumers, NRECA, Undersigned States, and West Virginia Commission argue that Order No. 1920's coordination reform shifts the costs of generator interconnection to load.[1420] In particular, Retail Regulators and Undersigned States argue that this requirement is another means to transfer network upgrade costs necessitated by generator interconnection to load and they contend, along with West Virginia Commission, that shifting these costs is not just and reasonable.[1421] Undersigned States further argue that this shift violates the FPA, and that Order No. 1920's failure to account for these effects is arbitrary and capricious.1422 Relatedly, PJM argues that this reform is arbitrary and capricious because it reopens accepted cost allocation methods in Order Nos. 1000 and 2023 that were built on the premise that the cost causer pays for the interconnection costs.[1423]

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[1419] *Id.* P 1118.

[1420] Retail Regulators Rehearing Request at 43-44; Ohio Consumers Rehearing Request at 8; NRECA Rehearing Request at 45; Undersigned States Rehearing Request at 37; West Virginia Commission Rehearing Request at 16.

[1421] Retail Regulators Rehearing Request at 43-44; Undersigned States Rehearing Request at 37; West Virginia Commission Rehearing Request at 16.

[1422] Undersigned States at 37.

[1423] PJM Rehearing Request at 36 (citing *Midwest ISO Transmission Owners*, 373

559. NRECA states that the Commission has failed to consider that its policies governing interconnection-related network upgrades—particularly allowing participant funding in RTOs/ISOs—are intended to result in a just and reasonable allocation of the costs of interconnection-related network upgrades.[1424] Industrial Customers argue that Order No. 1920 abruptly abandons participant funding, which it characterizes as a "longstanding" model that sends proper pricing signals for generation developers to select projects close to load while also protecting existing transmission customers from subsidizing interconnection of new generation.[1425] East Kentucky argues that the Commission:

> has not provided a reasonable explanation of how this requirement does not result in unjust, unreasonable, and unduly discriminatory transmission rates in violation of Section 206 of the Federal Power Act, 16 U.S.C. § 824e, and does not alter, without adequate explanation or evidence, the Commission's existing interconnection pricing and participant funding polices.[1426]

560. Industrial Customers state that the Commission ignored arguments that the Commission must rationally explain its decision to depart from the existing just and reasonable "but for" policy of Order No. 2003.[1427] Industrial Customers argue that the

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F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *State Farm*, 463 U.S. at 43; *Wis. Gas Co. v. FERC*, 770 F.2d at 1156; *see also* Industrial Consumers Rehearing Request at 48.

[1424] NRECA Rehearing Request at 48.

[1425] Industrial Customers Rehearing Request at 41.

[1426] East Kentucky Rehearing Request at 3.

[1427] Industrial Customer Rehearing Request at 41.

Commission should not justify its "cost allocation techniques by arguing that interconnection costs for renewable energy resources are too high and should be socialized across all transmission customers."[1428] Industrial Customers further argue that Order No. 1920 changes prior Commission policies without setting forth a reasonable and adequate explanation for resulting shifting of costs.[1429]

561. Ohio Consumers argue that Order No. 1920 is inconsistent with Order No. 2003 incentives because it shifts network upgrade costs that would have incentivized generation developers to locate in "the right area."[1430] NRECA argues that requiring evaluation and selection of unbuilt interconnection-related network upgrades in the existing Order No. 1000 regional transmission planning and cost allocation processes gives an undue preferential treatment to generation developers, a group that would ordinarily fund the network upgrades in the first instance.[1431] Further, NRECA states that the Commission has made no finding that the Commission's policies allowing participant funding in RTOs/ISOs for interconnection-related network upgrades have become unjust and unreasonable and should be replaced.[1432]

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[1428] *Id.* at 43.

[1429] *Id.* at 45.

[1430] Ohio Consumers Rehearing Request at 8-9; *see also* Industrial Consumers Rehearing Request at 42.

[1431] NRECA Rehearing Request at 46.

[1432] *Id.* at 48.

### 3. Commission Determination

562. We sustain Order No. 1920 and find that the coordination requirements in Order No. 1920 do not require changes to existing cost allocation methods that transmission providers have adopted in either the generator interconnection or existing Order No. 1000 regional transmission planning and cost allocation processes. Therefore, those existing cost allocation methods adopted by transmission providers remain intact.

563. To this point, in response to Retail Regulators, Ohio Consumers, NRECA, Undersigned States, West Virginia Commission, and PJM, we first note that the coordination reform does not alter existing cost allocation methods or create a new cost allocation method for generator interconnection processes. Rather, the purpose of the coordination reform is to require transmission providers to *evaluate*, in the existing Order No. 1000 regional transmission planning and cost allocation processes, certain (i.e., that qualify under the criteria established in Order No. 1920) interconnection-related transmission needs that were not addressed through the generator interconnection process because the identified interconnection-related network upgrades were never constructed pursuant to that process. If an interconnection customer enters into a generator interconnection agreement, the transmission provider will construct the identified interconnection-related network upgrades and allocate their costs in accordance with the transmission provider's Commission-accepted cost allocation approach for such interconnection-related network upgrades. If an interconnection customer does not enter into a generator interconnection agreement for its interconnection request, however, the identified interconnection-related network upgrades will not be constructed pursuant to

the generator interconnection process; thus, the generator interconnection cost allocation approach would not apply.

564. Moreover, in response to NRECA and PJM, the coordination reform does not create a new regional cost allocation method for the existing Order No. 1000 regional transmission planning and cost allocation processes. Instead, transmission providers must now, pursuant to this reform, *evaluate* certain interconnection-related transmission needs pursuant to their existing Order No. 1000 regional transmission planning and cost allocation processes. The transmission provider may adopt the evaluation method and selection criteria from any of its existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability process) to evaluate and potentially select transmission facilities that address these transmission needs. To the extent that such a transmission facility is selected, it will have met the selection criteria for the applicable Order No. 1000 regional transmission planning process and be eligible for cost allocation pursuant to a regional cost allocation method that has been found to allocate costs of transmission facilities selected through that process in a manner that is at least roughly commensurate with benefits.

565. We reiterate, however, that there is no obligation for transmission providers to select a transmission facility that addresses the interconnection-related transmission need that must be evaluated pursuant to this reform.[1433] As the Commission stated in Order No. 1920, in order for the transmission facility associated with the relevant

[1433] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1156.

interconnection-related transmission need to be eligible for cost allocation pursuant to transmission providers' existing Order No. 1000 regional cost allocation method, the transmission provider "will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution."[1434] The Commission also stated that "if a regional transmission facility that addresses identified interconnection-related transmission needs is not selected as part of the regional transmission planning process, then the associated regional cost allocation method would not apply."[1435] The Commission explained that, to the extent that the coordination reform results in transmission providers selecting a transmission facility that, among other things, addresses an interconnection-related transmission need in the existing Order No. 1000 regional transmission planning and cost allocation processes, they would have done so because the selected transmission facility was evaluated and determined by the transmission provider to be eligible for selection in the regional transmission plan for purposes of cost allocation and is the more efficient or cost-effective regional transmission solution. Moreover, we reiterate that the reform adopted here does not compel transmission providers to adopt a new cost allocation method for transmission facilities that address interconnection-related transmission needs.

[1434] *Id.* P 1117.

[1435] *Id.*

### D. Gaming

#### 1. Order No. 1920 Requirements

566. In Order No. 1920 the Commission did not adopt revisions to the proposed coordination reform in response to assertions that the reform would lead to "gaming," resulting in spurious interconnection requests. The Commission explained that interconnection requests require significant financial commitments from interconnection customers, which the Commission made more stringent in Order No. 2023. Consequently, the Commission considered it unlikely that an interconnection customer would submit multiple interconnection requests in multiple interconnection queue cycles to trigger the requirement for transmission providers to evaluate, as part of their existing Order No. 1000 regional transmission planning and cost allocation processes, regional transmission facilities that may address certain interconnection-related transmission needs. The Commission noted that an interconnection customer would face various risks pursuing such a strategy, including the risk that the regional transmission solution for the interconnection-related transmission need is not selected, and the risk that the newly created interconnection or transmission capacity is allocated to a different transmission or interconnection customer.[1436]

#### 2. Requests for Rehearing and Clarification

567. PJM and NRECA argue that Order No. 1920 is arbitrary and capricious because it creates perverse incentives for generation developers to game the interconnection process

[1436] *Id.* P 1119.

and shift interconnection-related network upgrade costs in an unduly discriminatory manner onto transmission customers.[1437] PJM and NRECA argue that the evidence does not support the Commission's reasoning that the stringent financial commitments required in the interconnection process will prevent gaming.[1438]

568. PJM states that, in its generator interconnection process, an interconnection customer's initial readiness deposit is only at risk prior to the interconnection customer learning its assigned network upgrade cost responsibility.[1439] PJM further states that, for a hypothetical 300 MW project that would trigger the $30 million dollar threshold in the final rule,[1440] the interconnection customer would only risk its readiness deposit of $1.2 million prior to withdrawing and having to post an additional deposit.[1441] PJM asserts that a sophisticated developer can leverage that low risk and enhance its chances of selection for PJM's Regional Transmission Expansion Plan (RTEP) by submitting well-formed and strategically positioned, but specious, interconnection requests.[1442] PJM asserts that, as a result, such developers can flood the PJM interconnection process with speculative and larger than necessary interconnection requests and withdraw shortly after

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[1437] PJM Rehearing Request at 33; NRECA Rehearing Request at 44, 46-47.

[1438] PJM Rehearing Request at 33; NRECA Rehearing Request at 46.

[1439] PJM Rehearing Request at 34.

[1440] Order No. 1920, 187 FERC ¶ 61,068 at P 1155.

[1441] PJM Rehearing Request at 35.

[1442] *Id.* at 36.

the required network upgrade costs are identified.[1443] PJM asserts that this would force it to reconsider RTEP upgrades that would incorporate the needed network upgrades and assign cost responsibility to load rather than to the generation developers.[1444]

569. PJM asserts that the final rule discounts these concerns despite PJM's demonstration that the risk-to-benefit ratio heavily favors the submission of speculative interconnection requests for a relatively low at-risk deposit. PJM argues that this risk-to-benefit ratio justifies the potential risk of non-selection in RTEP that a developer may face.[1445]

### 3. Commission Determination

570. We do not find persuasive arguments raised on rehearing and continue to find that no revisions to Order No. 1920's coordination requirement are necessary to address the speculative gaming concerns raised in this proceeding.[1446] With respect to PJM's specific generator interconnection process, we disagree with PJM that the risk an interconnection customer faces of losing only its readiness deposit if it withdraws is too low a risk to mitigate gaming concerns. Specifically, PJM's own hypothetical example demonstrates that an interconnection customer would risk losing $1.2 million for a single interconnection request, a risk that that we do not consider inconsequential. Moreover,

[1443] *Id.* at 35.

[1444] *Id.*

[1445] PJM Rehearing Request at 36.

[1446] Order No. 1920, 187 FERC ¶ 61,068 at P 1119.

for a single interconnection customer to attempt this gaming strategy, it would have to put its study and readiness deposits at risk in at least two interconnection queue cycles, and therefore would put at risk $2.4 million ($1.2 million per cycle) for the underlying interconnection-related transmission need to trigger the repeat identification criterion to qualify for evaluation in the Order No.1000 regional transmission planning and cost allocation processes.[1447] Therefore, the risk is higher than what PJM asserts.

571. Additionally, we continue to find it unlikely that an interconnection customer would submit multiple interconnection requests (in multiple interconnection queue cycles) to trigger this requirement because the interconnection customer would face additional uncertainty in that transmission providers may not select a transmission facility that addresses the interconnection-related network upgrade in a regional transmission plan for purposes of cost allocation. We also reiterate that pursuing such a strategy would entail other risks, including the risk that any of the five qualifying criteria will not be met and the possibility that the newly created interconnection or transmission capacity will not benefit the interconnection customer that submitted, and withdrew, the interconnection requests in multiple interconnection queue cycles because the entity that withdrew the interconnection requests has no preferential claim to that capacity.[1448] For these reasons, we believe the financial risks and process-related restrictions make it unlikely that a generation developer would risk time and resources to "game" this process

[1447] *Id.* PP 1119, 1145.

[1448] *See id.* P 1119.

in the hope of benefiting from an uncertain process, which is highly unlikely to produce the generation developer's preferred result.

### E. Transmission Planning Process Evaluation

#### 1. Order No. 1920 Requirements

572. In Order No. 1920, the Commission required transmission providers in each transmission planning region to evaluate regional transmission facilities that address certain interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes instead of in Long-Term Regional Transmission Planning, as was proposed in the NOPR. The Commission explained that by requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes, such needs will be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions.[1449]

573. The Commission agreed with commenters that future interconnection-related transmission needs will be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios. The Commission disagreed with commenters that asserted that the Commission's coordination proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support generator

[1449] *Id.* P 1126.

interconnections. The Commission anticipated that as transmission providers gain experience with Long-Term Regional Transmission Planning they will identify fewer interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process because transmission providers will plan to address Long-Term Transmission Needs, including those driven by Factor Category One: federal, federally-recognized Tribal, state, and local laws and regulations that affect the future resource mix and demand; Factor Category Two: federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; Factor Category Six: generator interconnection requests and withdrawals, and Factory Category Seven: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, through Long-Term Regional Transmission Planning.[1450]

### 2. Requests for Rehearing and Clarification

574. NRECA and East Kentucky argue that the Commission did not provide sufficient notice and opportunity to comment on the final rule's requirement to evaluate for selection transmission facilities to address identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation

[1450] *Id.* P 1127.

processes rather than in Long Term-Regional Transmission Planning process, as the NOPR proposed.[1451]

575. Clean Energy Associations claim that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate network upgrades that address interconnection-related transmission needs in Long-Term Regional Transmission Planning.[1452] Clean Energy Associations argue that if one assumes that the Order No. 1920 rationale is true, i.e., that the existing Order No. 1000 regional transmission planning and cost allocation processes are a faster and more effective means of getting these facilities built, then such rationale does not justify the Commission's failure to also require evaluation of those upgrades in Long-Term Regional Transmission Planning.[1453] Clean Energy Associations allege that Order No. 1920, by limiting the mandatory consideration of interconnection-related network upgrades to the existing Order No. 1000 regional transmission planning and cost allocation processes, will necessarily fail to require transmission providers to evaluate benefits of transmission facilities that would result from their selection. Clean Energy Associations allege that any transmission upgrade, including interconnection-related network upgrades, is more likely to be selected in the "more robust" Long-Term Regional Transmission Planning,

[1451] East Kentucky Rehearing Request at 1-2; NRECA Rehearing Request at 15-16.

[1452] Clean Energy Associations Rehearing Request at 4-6.

[1453] *Id.* at 6.

which they believe is consistent with the Commission's justifications of the reform and supported by the record.[1454]

576. Clean Energy Associations assert that the Commission's expectation that fewer interconnection-related network upgrades would be identified over time, in part due to transmission providers' consideration of Factor Category Six (Generator Interconnection Requests and Withdrawals), is no grounds to deny a parallel path for transmission providers to evaluate interconnection-related transmission needs through Long-Term Regional Transmission Planning because the categories of factors apply to identifying Long-Term Transmission Needs, rather than evaluating specific facilities for possible selection.[1455] Clean Energy Associations claim that the Commission's requirement to evaluate interconnection-related transmission needs is more analogous to the evaluation requirements than to the Long-Term Scenarios requirements of Long-Term Regional Transmission Planning. Clean Energy Associations argue, therefore, that it is not just and reasonable, nor is it comparable, to assume that Factor Category Six is duplicative of evaluating interconnection-related network upgrades in Long-Term Regional Transmission Planning.

577. Clean Energy Associations further argue that evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning may serve as a needed fail-safe for addressing current interconnection-related transmission needs if a particular

[1454] *Id.* at 7.

[1455] *Id.* at 7-8.

transmission provider's existing Order No. 1000 regional transmission planning and cost allocation processes prove to be ineffective for that purpose.[1456] Clean Energy Associations assert that to maximize the chances that more efficient or cost-effective projects will be successfully developed, the Commission should require transmission providers to evaluate qualifying interconnection-related network upgrades in both Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning and cost allocation processes.[1457]

578. Clean Energy Associations claim that the record demonstrates that interconnection-related network upgrades provide transmission benefits beyond the interconnection customers triggering them, and it is therefore reasonable to require their evaluation with comparable high-voltage, high-cost facilities in Long-Term Regional Transmission Planning.[1458] Clean Energy Associations also state that evaluation of interconnection-related network upgrades in Long-Term Regional Transmission Planning is the logical precedent for the voluntary funding option for interconnection customers because it will provide potential funders of the transmission facilities with a comparable way to evaluate the benefits of that facility.[1459]

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[1456] *Id.* at 8.

[1457] *Id.* at 9.

[1458] *Id.* at 10-11.

[1459] *Id.* at 11-12.

579. Finally, Clean Energy Associations request that, at a minimum, the Commission clarify that Order No. 1920 does not prohibit transmission providers from evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning.[1460]

580. Large Public Power argues that by specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes, Order No. 1920 will dramatically skew the Order No. 1000 processes and is fundamentally at odds with the Commission's objective of not disrupting planning for reliability and economic needs put in place under Order No. 1000.[1461] Large Public Power also argues that specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes is inconsistent with the approach to developing Long-Term Scenarios, which "call[s] for a holistic analysis which enables system planners to make informed, balanced decisions to address the unique Long-Term Transmission Needs of each planning region."[1462] Large Public Power asserts that the Commission failed to explain why generation interconnection application withdrawals should be the only consideration to determine

[1460] *Id.* at 12-13.

[1461] Large Public Power Rehearing Request at 21.

[1462] *Id.* at 21-22.

transmission needs under existing Order No. 1000 regional transmission planning and cost allocation processes.[1463]

581. PJM claims that the withdrawn and speculative interconnection requests, as potential drivers of regional transmission needs, would insert an unjustified level of uncertainty into its existing Order No. 1000 regional transmission planning and cost allocation processes.[1464] PJM also asserts that the final rule is arbitrary and capricious because it requires consideration of withdrawn interconnection requests in its near-term RTEP and provides them undue preference over interconnection requests that have taken all required steps to obtain site control, permits, and regulatory approvals and have paid deposits.[1465] PJM contends that under the final rule, the output of the RTEP process, which is used in the generator interconnection process, "would be inflated by the addition of questionable transmission upgrades."[1466] Thus, PJM claims, the RTEP and generator interconnection processes, which are meant to work in tandem, would become unnecessarily separated and infused with dubious inputs and drivers.[1467]

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[1463] Large Public Power Rehearing Request at 22.

[1464] PJM Rehearing Request at 37-38.

[1465] *Id.*

[1466] *Id.* at 38.

[1467] *Id*.

### 3. Commission Determination

582. We disagree with NRECA and East Kentucky that the Commission failed to provide adequate notice of and opportunity to comment on Order No. 1920's requirement that transmission providers in each transmission planning region evaluate for selection regional transmission facilities that address certain interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes instead of in Long-Term Regional Transmission Planning.[1468]

583. A final rule is a logical outgrowth of a proposed rule where "a reasonable member of the regulated class" could "anticipate the general aspects of the [final] rule."[1469] Order No. 1920 satisfies this standard because the NOPR explicitly requested comment on how the proposed reform "should interact with existing regional transmission planning processes and the Long-Term Regional Transmission Planning proposed herein,"[1470] which put parties on notice that the Commission was contemplating the change that

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[1468] East Kentucky Rehearing Request at 1-2; NRECA Rehearing Request at 15-16.

[1469] *Telesat Canada v. FCC*, 999 F.3d at 713-14 (quotations omitted). We note that, while requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes will allow such needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions, we believe that evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning would also be appropriate. The inability to require that transmission providers consider regional transmission facilities to address interconnection-related transmission needs in Order No. 1000 processes would not have prevented the Commission from issuing Order No. 1920.

[1470] NOPR, 179 FERC ¶ 61,028 at P 174.

NRECA and East Kentucky now argue is not a logical outgrowth of the NOPR. Courts have explained that "[n]otice suffices when [an agency] has 'expressly asked for comments on a particular issue or otherwise made clear that the agency was contemplating a particular change.'"[1471] Here, by requesting comment on the issue, the Commission put parties on notice that it was continuing to contemplate how the proposed reform should interact with both proposed Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.

584. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a "logical outgrowth" of the proposed rule.[1472] The final rule is a logical outgrowth of the NOPR in this regard. In the NOPR, the Commission proposed to require that transmission providers evaluate for selection in the regional transmission plan for purposes of cost allocation regional transmission facilities to address certain interconnection-related needs that meet specific qualifying criteria established by the Commission.[1473] Order No. 1920 adopted this requirement and mandated that such consideration occur in existing Order No. 1000 regional transmission planning and cost

[1471] *Brennan v. Dickson*, 45 F.4th at 69 (quoting *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d at 1081).

[1472] *Long Island Care*, 551 U.S. at 174-75; *see also Am. Paper Inst. v. EPA*, 660 F.2d at 959 n.13 ("An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given." (emphasis added)).

[1473] NOPR, 179 FERC ¶ 61,028 at P 166.

allocation processes,[1474] rather than in Long-Term Regional Transmission Planning, as the NOPR proposed.[1475] The Commission explained that this change will allow interconnection-related transmission needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions. We find that this change satisfies the logical outgrowth test because while the Commission modified the type of regional transmission planning and cost allocation processes that would be subject to coordination with interconnection-related transmission needs, it retained the underlying requirement that such coordination occur. Thus, Order No. 1920's requirement "follow[s] logically from" the NOPR because the NOPR "adequately frame[d] the subjects for discussion."[1476]

585. We are unpersuaded by Clean Energy Associations' assertion that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate network upgrades that address interconnection-related transmission needs in Long-Term Regional Transmission Planning. We continue to find that evaluating interconnection-related transmission needs associated with this coordination requirement is more appropriate in the existing Order No. 1000 regional transmission planning and cost allocation processes than in Long-Term Regional Transmission Planning because such evaluation would occur at shorter intervals and would be more likely to result in

[1474] Order No. 1920, 187 FERC ¶ 61,068 at P 1126.

[1475] NOPR, 179 FERC ¶ 61,028 at P 167.

[1476] *Conn. Light & Power Co. v. Nuclear Regulatory Comm'n*, 673 F.2d at 533.

expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.[1477] We find that it is unnecessary to require transmission providers to also evaluate interconnection-related transmission needs associated with this coordination requirement in Long-Term Regional Transmission Planning because the coordination requirement in Order No. 1920 is just and reasonable and sufficient to address the need for reform.

586. In addition, we reiterate that transmission providers must consider future interconnection-related transmission needs as a driver of Long-Term Transmission Needs in Long-Term Regional Transmission Planning through the development of Long-Term Scenarios, which must incorporate generator interconnection withdrawals in Factor Category Six (Generator Interconnection Requests and Withdrawals).[1478] Factor Category Six allows transmission providers to consider a broader range of potential interconnection-related transmission needs compared to the interconnection-related transmission needs that meet the coordination requirement's qualifying criteria. Moreover, to the extent that an interconnection-related transmission need is not addressed according to this coordination requirement, transmission providers may choose to consider similar interconnection-related transmission needs as Long-Term Transmission Needs and evaluate Long-Term Regional Transmission Facilities to address those needs

[1477] Order No. 1920, 187 FERC ¶ 61,068 at P 1126.

[1478] *Id.* PP 1127-1128.

in Long-Term Regional Transmission Planning. Therefore, we believe that requiring transmission providers to evaluate interconnection-related transmission needs identified by this coordination requirement in Long-Term Regional Transmission Planning would be redundant to existing Order No. 1920 requirements and could inappropriately limit the scope of the interconnection-related transmission needs that transmission providers consider in Long-Term Regional Transmission Planning.

587. On this point, we disagree with Clean Energy Associations' claim that it is not just and reasonable, nor is it comparable, to assume Factor Category Six is duplicative of evaluating interconnection-related network upgrades in Long-Term Regional Transmission Planning, and that this coordination requirement is more analogous to the Long-Term Regional Transmission Planning evaluation requirements. Both the qualifying criteria of the coordination requirement and the categories of factors of the Long-Term Scenarios requirements (in Long-Term Regional Transmission Planning) establish how transmission providers identify transmission needs. We recognize that the coordination requirement mandates the evaluation of regional transmission facilities to address interconnection-related transmission needs associated with this coordination requirement, albeit allowing for flexibility in how transmission providers evaluate such facilities for selection, but Long-Term Regional Transmission Planning does not mandate evaluation of a specific type of transmission facility.[1479] However, the requirement to evaluate regional transmission facilities associated with the coordination requirement is

[1479] *Id.* P 1111.

similar to the Long-Term Regional Transmission Planning requirement for transmission providers to establish a process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs (which, as discussed above, will include future interconnection-related transmission needs). This explanation addresses Clean Energy Associations' concern that Order No. 1920 will necessarily fail to require transmission providers to evaluate benefits of transmission facilities to address interconnection-related transmission needs through Long-Term Regional Transmission Planning.

588. In response to Clean Energy Associations' request for clarification that Order No. 1920 does not prohibit transmission providers from evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning, we reiterate that future interconnection-related transmission needs must be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios.[1480] We clarify that Order No. 1920 does not prohibit transmission providers from proposing on compliance how they will identify and evaluate future interconnection-related transmission needs in Long-Term Regional Transmission Planning. However, we will not prejudge Clean Energy Associations' proposal for a "parallel path" for identifying and evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning using the coordination requirement's

[1480] *Id.* P 1127.

qualification criteria.[1481] If any transmission provider chooses to develop additional processes to address interconnection-related transmission needs in Long-Term Regional Transmission Planning, they must demonstrate that the proposal is consistent with or superior to Order No. 1920's requirements.

589. We are not persuaded by Large Public Power's argument that, in Order No. 1920, the Commission is specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes. To this point, we first note that Order No. 1920 adopts not one, but five, criteria for interconnection-related transmission needs to be evaluated through existing Order No. 1000 regional transmission planning and cost allocation processes. That is, evaluation is only required when the interconnection-related network upgrades driving interconnection-related transmission needs meets the five qualification criteria established in Order No. 1920.[1482]

590. Furthermore, the evaluation requirement only requires transmission providers to *evaluate* interconnection-related transmission needs in the Order No. 1000 regional transmission planning process. It does not require that transmission providers use interconnection-related transmission needs as a criterion to decide whether to select a regional transmission facility in the Order No. 1000 regional transmission planning process nor does it require that the interconnection-related transmission need be resolved.

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[1481] *Id.* P 1145.

[1482] *Id.*

As the Commission explained, these requirements provide flexibility in how transmission providers evaluate transmission facilities for selection by allowing them to adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability processes) to evaluate and potentially select these types of transmission facilities. The Commission thus permitted transmission providers to propose the best method to incorporate this new requirement for their transmission planning region and encouraged transmission providers to consider, as part of the evaluation process, whether regional transmission facilities that address certain identified interconnection-related transmission needs may also address other regional transmission needs more efficiently or cost-effectively.[1483]

591. We also disagree with PJM's assertions that the Order No. 1920 requirement is arbitrary and capricious because the requirement would insert an unjustified level of uncertainty into its existing Order No. 1000 regional transmission planning and cost allocation processes by requiring consideration of withdrawn interconnection requests in its near-term RTEP. As explained here and in Order No. 1920, we are not requiring that transmission providers develop transmission facilities through the Order No. 1000 regional transmission planning and cost allocation processes as transmission solutions to address interconnection-related transmission needs. The coordination reform simply creates an avenue for evaluation of qualifying interconnection-related transmission needs

[1483] *Id.* P 1111.

in the existing Order No. 1000 regional transmission planning and cost allocation processes. Further, Order No. 1920 gives transmission providers flexibility to "adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability processes) to evaluate and potentially select these types of transmission facilities"[1484]

592. Additionally, we disagree with PJM that the Order No. 1920 requirement gives undue preference to withdrawn interconnection requests. Instead, the requirement addresses a barrier to entry for new generation resources, where repeated interconnection requests are increasingly withdrawn due to sticker shock from the estimated costs of the required interconnection-related network upgrades. The qualifying requirements, however, disqualify from these requirements interconnection-related transmission needs memorialized in generator interconnection agreements (i.e., that are ready to move forward with project development in the generator interconnection process). Consequently, pursuant to the coordination reformation requirements, no interconnection customer would benefit from having the upgrade costs that it would otherwise pay allocated instead through transmission rates. Rather, in the circumstance that Order No. 1920 addresses, no interconnection customer is willing to pay the estimated costs of the interconnection-related network upgrades. Therefore, there would be no undue preference because if the qualifying criteria are met, there is no longer an interconnection

[1484] *Id.*

request or interconnection customer associated with the qualifying interconnection-related transmission need.

593. Moreover, in response to PJM's assertion that the output of the RTEP process, which is used in its generator interconnection process, "would be inflated by the addition of questionable transmission upgrades," we again note that the Order No. 1920 requirement does not require that transmission providers resolve interconnection-related transmission needs, including resolving them through selection of transmission facilities; that is, Order No. 1920 neither requires nor guarantees a specific outcome. Rather, transmission providers must consider the interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes and determine whether there is a more efficient or cost-effective transmission solution, under the existing evaluation and selection criteria in the existing Order No. 1000 regional transmission planning and cost allocation processes.

## VII. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

### A. Order No. 1920 Requirements

594. In Order No. 1920, the Commission required transmission providers in each transmission planning region to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, the following enumerated alternative transmission technologies for each identified transmission need: (1) dynamic line ratings; (2) advanced power flow control devices; (3) advanced

conductors; and (4) transmission switching.[1485] This list of enumerated alternative transmission technologies that the Commission required transmission providers in each transmission planning region to consider expanded on the Commission's proposed list of alternative transmission technologies, which only proposed to require the consideration of dynamic line ratings and advanced power flow control devices.[1486] The Commission further required that transmission providers consider each of these enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities. Thus, the Commission required that for each identified transmission need, when evaluating regional transmission facilities for potential selection, transmission providers must consider whether regional transmission facilities that incorporate, or solely consist of, any of the enumerated list of alternative transmission technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies.[1487]

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[1485] Order No. 1920, 187 FERC ¶ 61,068 at P 1198. In Order No. 1920, the Commission defined advanced transmission technologies as "a range of permissible present and future technologies, and is defined relative to conventional aluminum conductor steel reinforced conductors." *Id.* P 1243. The Commission further clarified that "advanced conductors include, but are not limited to, superconducting cables, advanced composite conductors, advanced steel cores, high temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors." *Id.*

[1486] NOPR, 179 FERC ¶ 61,028 at P 272.

[1487] Order No. 1920, 187 FERC ¶ 61,068 at P 1198.

595. The Commission further required that transmission providers' evaluation of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions.[1488] In response to requests for additional transparency, the Commission adopted the NOPR proposal to expand the existing requirement established in Order No. 1000 for transmission providers' evaluation processes to culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected. Specifically, the Commission required that the determination include an explanation that is sufficiently detailed for stakeholders to understand why dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching were or were not incorporated into selected regional transmission facilities.[1489]

### B. Requests for Rehearing and Clarification

#### 1. General Requests for Rehearing and Clarification

##### a. Requests for Rehearing and Clarification

596. Large Public Power requests clarification that transmission providers may use engineering judgment in considering which transmission elements should be analyzed as candidates for alternative transmission technologies. Specifically, Large Public Power explains that, while it does not challenge the Commission's general approach to alternative transmission technologies, requiring transmission providers to conduct

[1488] *Id.* P 1199.

[1489] *Id.* P 1214.

resource intensive and detailed production cost simulations for each technology for each existing transmission element would be burdensome and expensive. Large Public Power asks the Commission to clarify that planning engineers may exercise informed discretion regarding the planning horizon within which alternative transmission technologies are of value. Finally, Large Public Power states that it understands that all relevant judgments must be supported and subject to examination and review.[1490]

597. On rehearing, NESCOE argues that the Commission should require transmission providers to prioritize alternative transmission technologies to serve as the starting point for addressing identified transmission needs.[1491] NESCOE states that, absent such prioritization of alternative transmission technologies, rates remain at risk of being unjust and unreasonable.[1492] NESCOE asks the Commission to direct transmission providers to incorporate tariff procedures establishing a rebuttable presumption that the incorporation of alternative transmission technologies as a solution to an identified Long-Term Transmission Need or existing Order No. 1000 transmission need would result in a more efficient or cost-effective transmission solution. NESCOE asserts that such a directive would both maintain the flexibility envisioned by Order No. 1920 and place the burden on transmission providers to demonstrate why alternative transmission technologies are

[1490] Large Public Power Request for Rehearing at 13-16.

[1491] NESCOE Request for Rehearing at 6, 22-25, 34.

[1492] *Id.* at 25.

not, either alone or as a solution component, a more efficient or cost-effective solution.[1493]

### b. Commission Determination

598. We grant, in part, Large Public Power's request for clarification regarding "engineering judgment" in analyzing transmission elements for alternative transmission technologies.[1494] In particular, we do not require detailed production cost simulations to demonstrate costs and benefits of each alternative transmission technology for each existing transmission element, and we clarify that transmission providers have flexibility to apply good engineering judgment to identify the specific transmission elements that are likely candidates for specific enumerated alternative transmission technologies. We recognize that a transmission provider's consideration of alternative transmission technologies will likely depend on the particulars of the transmission provider's transmission system. In that context, transmission providers may be able to rapidly determine if a certain alternative transmission technology is inappropriate for further study on a specific transmission element.[1495]

599. We reiterate, however, that transmission providers in each transmission planning region must consider, as discussed above, dynamic line ratings, advanced power flow

[1493] *Id.* at 24-25.

[1494] Large Public Power Request for Rehearing at 13-16.

[1495] We note that this is consistent with the Commission's findings in Order No. 2023. *See, e.g.*, Order No. 2023, 187 FERC ¶ 61,068 at P 1590.

control devices, advanced conductors, and transmission switching for each identified transmission need during Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. We further reiterate that transmission providers must consider each of those alternative transmission technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities.[1496] Such consideration of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions and with the Commission's requirements established in Order No. 1920.[1497] Finally, consistent with Large Public Power's understanding,[1498] nothing in this clarification obviates the requirement for transmission providers to support their determinations,[1499] the Commission's transparency requirements, or the potential to challenge a transmission provider's consideration of the enumerated alternative transmission technologies.[1500]

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[1496] Order No. 1920, 187 FERC ¶ 61,068 at P 1198.

[1497] *Id.* P 1199.

[1498] Large Public Power Request for Rehearing at 16.

[1499] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1214.

[1500] *See, e.g.*, *id.* P 224. The Order No. 890 transmission planning principles include transparency and obligate transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. *See* Order No. 890, 118 FERC ¶ 61,119 at PP 435, 471. In Order No. 890, the transparency transmission planning principle also requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. Order

600. We deny NESCOE's request that the Commission establish a rebuttable presumption in favor of alternative transmission technologies.[1501] Rather, it is the Commission's longstanding policy to remain fuel and technology neutral.[1502] As such, and consistent with the Commission's finding in Order No. 2023,[1503] we decline to create a presumption in favor of substituting alternative transmission technologies in either Long-Term Regional Transmission Planning or the existing Order No. 1000 regional transmission planning processes. There is insufficient evidence in the record to presume that an alternative transmission technology would be the more efficient or cost-effective solution as a replacement for a traditional wires-based solution or that the addition of an alternative transmission technology to a potential transmission solution would necessarily result in a more efficient or cost-effective solution in all instances. Consequently, Order No. 1920 mandates a process for the consideration of alternative transmission technologies, not specific outcomes.[1504]

No. 890, 118 FERC ¶ 61,119 at P 471.

[1501] NESCOE Request for Rehearing at 6, 22-25.

[1502] *See*, *e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 437 ("We emphasize that the Commission's policies are technology neutral, and we are not establishing a preference for certain types of generation or energy end uses.").

[1503] Order No. 2023, 184 FERC ¶ 61,054 at P 1582 ("This final rule does not create a presumption in favor of substituting alternative transmission technologies for necessary traditional network upgrades, either categorically or in specific cases.").

[1504] *See id.*

### 2. Technology Specific Requests for Rehearing and Clarification

#### a. Requests for Rehearing and Clarification

601. Clean Energy Associations and PIOs assert that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate storage resources that perform a transmission function as alternative transmission technologies.[1505] Clean Energy Associations and PIOs disagree that the Commission's finding that "whether an electric storage resource performs a transmission function requires a case-by-case analysis" justifies its exclusion from the list of enumerated alternative transmission technologies because, they argue, all transmission solutions are studied on a case-by-case basis.[1506] Clean Energy Associations further argue that whether a particular storage resource is performing a transmission function is completely separate and distinct from the issue of whether a storage resource that *has* been determined on a case-specific basis to be providing a transmission function should be included in the list of enumerated alternative transmission technologies.[1507] Clean Energy Associations argue that the proper approach is to require storage resources that would be providing a

[1505] Clean Energy Associations Rehearing Request at 26-30; PIOs Rehearing Request at 7, 38-43 (citations omitted).

[1506] Clean Energy Associations Rehearing Request at 26 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1245); PIOs Rehearing Request at 40.

[1507] Clean Energy Associations Rehearing Request at 26.

transmission function be included in the enumerated list of alternative transmission technologies.[1508]

602. Clean Energy Associations assert that the Commission's decision to exclude storage providing a transmission function is not supported by substantial evidence and is unduly discriminatory.[1509] Clean Energy Associations argue that the record evidence demonstrates that storage can provide efficient or cost-effective solutions and that the Commission did not cite evidence that considering storage in transmission planning is potentially detrimental or lacks stakeholder support.[1510] Clean Energy Associations further argue that the Commission failed to distinguish storage resources providing a transmission function from advanced conductors and transmission switching technologies, which were added to the advanced technologies enumerated in the final rule. Clean Energy Associations assert that there is no rational basis to exclude storage resources from the list and that it is unduly discriminatory to exclude storage.[1511] Clean Energy Associations state that the Commission should grant rehearing and require

[1508] *Id.* at 27.

[1509] *Id.* at 26-30.

[1510] *Id.* at 27-28 (citing *Emera Me.*, 854 F.3d at 22).

[1511] *Id.* at 29-30 (citing *FPL Energy Marcus Hook, L.P. v. FERC*, 430 F.3d 441, 449 (D.C. Cir. 2005); *Emera Me.*, 854 F.3d at 22).

transmission providers to consider storage as a transmission asset in Long-Term Regional Transmission Planning.[1512]

603. PIOs assert that the Commission's omission of storage as a transmission asset from the list of alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes was arbitrary and capricious because the Commission did not meaningfully engage with commenters or provide a reasoned basis for its decision.[1513] PIOs urge the Commission to grant rehearing to require transmission providers to evaluate storage as a part of Long-Term Regional Transmission Planning.[1514]

604. PIOs observe that the Commission has identified considerations that, together, ensure that a selected storage resource will serve a transmission function; nevertheless, they argue the Commission failed to explain why it did not simply note that the use of storage as a transmission asset will ultimately need to comply with these considerations, rather than omitting it as an alternative transmission technology.[1515] PIOs state that under the Commission's approach in Order No. 1920, in which it explained that "transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to

[1512] *Id.* at 30.

[1513] PIOs Rehearing Request at 38, 42-43 (citations omitted).

[1514] *Id.* at 43.

[1515] *Id.* at 41-42 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1245, n.2671; *Sw. Power Pool, Inc*., 183 FERC ¶ 61,153, at P 29 (2023)).

specific transmission needs," it need not dictate how transmission providers evaluate storage as transmission.[1516]

605. CTC Global states that the Commission's definition of advanced conductors allows for the consideration of advanced conductors that are not representative of the capabilities represented by the Commission.[1517] CTC Global states that this may allow transmission providers to avoid consideration of the types of advanced conductors that Congress intended to be reviewed in the Energy Policy Act of 2005 and that the US DOE has described in reports.[1518] For this reason, CTC Global requests clarification, or in the alternative rehearing, that the definition of advanced conductors will ensure that sufficiently advanced conductors—which at a given voltage increase power flow capabilities by at least 1.5 times, decrease losses by 20% or more, and improve conductor sag performance—are included in regional transmission planning processes. CTC Global states that such a clarification is needed to ensure that the conditions that the Commission identified as leading to unjust and unreasonable rates are addressed and argues that failure to do so will continue to result in project identification that may not be more efficient or cost-effective than alternatives.[1519]

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[1516] *Id.* at 41 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1210).

[1517] CTC Global Rehearing Request at 2-3.

[1518] *Id.* (citing Energy Policy Act of 2005, Pub. L. No. 109-58, § 1223, 119 Stat. 594, 953-954 (2005)).

[1519] *Id.* at 2-5, 10-17.

606. Invenergy argues that the Commission should clarify that HVDC is an alternative transmission technology that may be considered in long-term and nearer-term regional transmission planning processes.[1520] Invenergy explains that the Commission did not specifically address the use of HVDC, despite PIOs arguing for its consideration as an alternative transmission technology. Invenergy agrees with PIOs' comments and states that PIOs clearly demonstrated in their comments how HVDC can be beneficial.[1521] In light of this demonstration, Invenergy asks the Commission to grant clarification that transmission providers are not precluded from considering HVDC like other alternative transmission technologies or other potential solutions that may be considered in long-term and nearer-term regional transmission planning processes.[1522]

**b. Commission Determination**

607. We sustain the Commission's decision in Order No. 1920 to not include storage as a transmission asset in the enumerated list of alternative transmission technologies that transmission providers must consider.[1523] We continue to find that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis of how a particular electric storage resource would be operated as well as any requirements set forth in an OATT governing selection of such electric storage

[1520] Invenergy Rehearing Request at 10-13.

[1521] *Id.* at 11-12 (citing PIOs NOPR Initial Comments at 22, Ex. A at PP 20, 22,).

[1522] *Id.* at 13.

[1523] Order No. 1920, 187 FERC ¶ 61,068 at P 1245.

resources as transmission solutions.[1524] Therefore, we continue to find that it is inappropriate to require the consideration of storage that performs a transmission function on a generic basis. While Clean Energy Associations and PIOs argue that any transmission solution requires a case-by-case analysis, electric storage resources require an *additional* case-by-case analysis that distinguishes them from other transmission solutions and from the enumerated list of alternative transmission technologies.[1525] Namely, that type of analysis would require the transmission provider to determine, among other considerations: (1) that the electric storage resource would strictly act as a transmission asset, connected to the transmission system as a transmission facility solely to support that transmission provider's transmission system; (2) the electric storage resource's cost recovery, by ensuring that the electric storage resource's participation in markets is limited to only charging from, and discharging to, the transmission provider's transmission system as necessary to provide the services for which it was selected based on the cost of the maximum capacity needed to address the identified transmission issue; and (3) that the electric storage resource's construction would not impact the generator interconnection queue.[1526] We reiterate, however, that Order No. 1920 does not preclude

[1524] *Id.* In Order No. 2023, the Commission pointed to the process in SPP, which takes into account five considerations that, together, ensure that a selected electric storage resource will serve a transmission function. Order No. 2023, 184 FERC ¶ 61,054 at P 1599 (citing *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,153, at P 29 (2023)).

[1525] Order No. 2023, 184 FERC ¶ 61,054 at P 1599; Order No. 2023-A, 186 FERC ¶ 61,199 at P 640.

[1526] *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,153, at P 29 (2023).

transmission providers from considering other alternative transmission technologies that were not included in the enumerated list of alternative transmission technologies, including storage as a transmission asset, in their Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.[1527]

608. In response to CTC Global, we clarify that the requirement to consider alternative transmission technologies necessitates that transmission providers consider the types of advanced conductors that Congress intended to be reviewed in the Energy Policy Act of 2005 and that the US DOE has described in its reports.[1528] However, we decline to alter the definition of an advanced conductor.[1529] We continue to find that advanced conductors include present and future transmission line technologies whose power flow capacities exceed the power flow capacities of conventional aluminum conductor steel

[1527] Order No. 1920, 187 FERC ¶ 61,068 at P 1247.

[1528] *See, e.g.*, U.S. Dep't of Energy, *Advanced Transmission Technologies* 25-28 (Dec. 2020), https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf; *see also* U.S. Dep't of Energy, *Pathways to Commercial Liftoff: Innovative Grid Deployment* 77 (2024), https://liftoff.energy.gov/wp-content/uploads/2024/05/Liftoff_Innovative-Grid-Deployment_Final_5.2-1.pdf; *see also* 42 U.S.C. § 16422(b) (directing the Commission to "encourage, as appropriate, the deployment of advanced transmission technologies"); *id.* § 16422(a) (defining "advanced transmission technology" as "a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility").

[1529] *See* CTC Global Rehearing Request at 4-5 (setting forth proposed modified definition).

reinforced conductors,[1530] and that advanced conductors include, but are not limited to, superconducting cables, advanced composite conductors, advanced steel cores, high temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors.[1531] However, we clarify that transmission providers, rather than considering just one of the six advanced conductor examples listed, must instead consider each of the six advanced conductor examples listed, and, as they determine appropriate, any additional advanced conductor which that transmission provider determines might be more efficient or cost-effective. In doing so, transmission providers must consider a range of advanced conductor options with a variety of performance and cost attributes, including those with the performance capabilities described by CTC Global.[1532] We deny CTC Global's request to add performance metrics to the definition of an advanced conductor because it would limit the scope of advanced conductors required to be considered and thereby eliminate from required consideration certain advanced conductors that may be more efficient or cost-effective in specific circumstances.

[1530] Order No. 1920, 187 FERC ¶ 61,068 at P 1198 n.2553.

[1531] *Id.* P 1243.

[1532] CTC Global Rehearing Request at 2-5 (requesting that the Commission clarify that advanced conductors are those that have power flow capabilities that exceed those of conventional aluminum conductor steel reinforced conductors at a given voltage by a factor of at least 1.5 times while decreasing electrical losses by 20% or more, and improve conductor sag performance, at the same or reduced weight per foot).

609. In response to Invenergy,[1533] we clarify that transmission providers are not precluded from considering HVDC facilities in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. In Order No. 1920, the Commission clarified that transmission providers are not precluded from considering other alternative transmission technologies that are not included in the enumerated list of alternative transmission technologies or other potential solutions in their Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.[1534] That clarification applies to the consideration of HVDC technologies.

## VIII. Regional Transmission Cost Allocation

### A. Obligation to File an *Ex Ante* Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop

#### 1. Logical Outgrowth

##### a. NOPR Proposals

610. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise their OATTs to include one of the following: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or

[1533] Invenergy Rehearing Request at 10-13.

[1534] Order No. 1920, 187 FERC ¶ 61,068 at P 1247.

more Relevant State Entities may voluntarily agree to a cost allocation method; or (3) a combination thereof.[1535]

611. The Commission noted that if states agree to a State Agreement Process instead of a Long-Term Regional Transmission Cost Allocation Method, certain Long-Term Regional Transmission Facilities selected in the regional transmission plan for purposes of cost allocation would lack a clear *ex ante* cost allocation method,[1536] and sought comment on whether the Commission should require transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs, in lieu of the proposed reform.[1537] The Commission requested comment on the appropriate outcome when Relevant State Entities fail to agree on a cost allocation method for all or a portion of Long-Term Regional Transmission Facilities, including whether in such circumstances the transmission providers should be required to establish a Long-Term Regional Transmission Cost Allocation Method.[1538]

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[1535] NOPR, 179 FERC ¶ 61,028 at P 302. The Commission explained that, for example, a "combination" approach may entail (i) providing a Long-Term Regional Transmission Cost Allocation Method for certain types of Long-Term Regional Transmission Facilities and providing a State Agreement Process for others; or (ii) providing for cost allocation for a Long-Term Regional Transmission Facility, portfolio, or type of such facilities partially based on a Long-Term Regional Transmission Cost Allocation Method and partially based on funding contributions in accordance with a State Agreement Process. *Id.* P 302 n.510.

[1536] *Id.* P 315.

[1537] *Id.* P 318.

[1538] *Id.* P 310.

### b. Order No. 1920 Requirements

612. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Methods[1539] for Long-Term Regional Transmission Facilities that are selected and permitted transmission providers to additionally revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process. The Commission required that a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities, and that if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop.[1540]

613. In Order No. 1920, the Commission stated that it was not imposing any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to

[1539] The Commission defined Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. Order No. 1920, 187 FERC ¶ 61,068 at P 1291.

[1540] *Id.* PP 1291-1292.

the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.[1541]

### c. Requests for Rehearing and Clarification

614. Several commenters argue that Order No. 1920 substantially departs from and is not a logical outgrowth of the NOPR because Order No. 1920 does not require transmission providers to adopt a State Agreement Process, consequently denying Relevant State Entities any meaningful opportunity to determine regional cost allocation.[1542] Arizona Commission asserts that, contrary to the NOPR, Order No. 1920 "effectively eliminates the use of a voluntary State Agreement Process, such as the one that has been used by PJM since Order No. 1000," which it asserts is "directly contrary to comments filed by state regulators."[1543] Idaho Commission argues that "[i]n a substantial departure from the NOPR, Order No. 1920 allows, but does not require, transmission providers in each transmission planning region to adopt a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities."[1544] Designated Retail Regulators similarly contend that Order No. 1920

[1541] *Id.* P 1429.

[1542] Arizona Commission Rehearing Request at 19; Idaho Commission Rehearing Request at 2, 5-6.

[1543] Arizona Commission Rehearing Request at 19.

[1544] Idaho Commission Rehearing Request at 5 (quotation marks omitted).

"drastically depart[s] from the NOPR" because it gives transmission providers complete discretion to decide whether to file a State Agreement Process or Long-Term Regional Transmission Cost Allocation method in its OATT, even if agreed to by the Relevant State Entities, which would relegate states to a transmission planning role akin to any other stakeholder.[1545]

615. Designated Retail Regulators and Arizona Commission also contend that Order No. 1920 violates the APA's notice-and-comment requirements because it requires transmission providers to set an *ex ante* cost allocation method that would apply as a backstop in certain circumstances, reducing states' bargaining power and setting up a mechanism to impose a regional cost allocation for preferential policy and corporate-driven projects when states do not consent.[1546]

**d. Commission Determination**

616. We find that the Commission's decision in Order No. 1920 not to require that transmission providers adopt a State Agreement Process is a logical outgrowth of the NOPR, and we thus disagree with arguments to the contrary. The NOPR did not propose to require a State Agreement Process but rather proposed to require transmission providers to include in their OATTs *either* a Long-Term Regional Transmission Cost

[1545] Designated Retail Regulators Rehearing Request at 47-50.

[1546] Arizona Commission Rehearing Request at 18; Designated Retail Regulators Rehearing Request at 47, 49-50.

Allocation Method, *or* a State Agreement Process, *or* a combination thereof.[1547] Furthermore, contrary to Arizona Commission's arguments, Order No. 1920 did not eliminate the State Agreement Process and instead permits transmission providers to revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process.[1548]

617. We also disagree with Arizona Commission's and Designated Retail Regulators' argument that Order No. 1920's requirement for transmission providers to revise their OATTs to include at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method is not a logical outgrowth of the NOPR proposal to allow transmission providers to choose to include either an *ex ante* regional cost allocation method, or a State Agreement Process, or a combination of both. Although the Commission in the NOPR proposed to allow transmission providers to choose between filing an *ex ante* Long-Term Regional Transmission Cost Allocation Method, a State Agreement Process, or some combination of both, the Commission also sought comment on "whether the Commission should require, instead of the reforms proposed in this section of the NOPR, public utility transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs."[1549] As courts have explained, notice is sufficient when an agency has "expressly asked for comments on a

[1547] NOPR, 179 FERC ¶ 61,028 at P 302.

[1548] Order No. 1920, 187 FERC ¶ 61,068 at PP 1291-1292.

[1549] NOPR, 179 FERC ¶ 61,028 at P 318.

particular issue or otherwise made clear that the agency was contemplating a particular change."[1550] By requesting comment on whether the Commission should require inclusion of an *ex ante* Long-Term Regional Transmission Cost Allocation Method, the Commission put parties on notice that the Commission was considering *the exact change* that it ultimately adopted in Order No. 1920. Therefore, in adopting the requirement that transmission providers file at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method, the Commission adhered to the APA's notice-and-comment requirements.[1551] To the extent Arizona Commission's and Designated Retail Regulators' argument was based on concerns about the states' role more broadly in Long-Term Regional Transmission Planning and cost allocation processes, we note that we

[1550] *Brennan v. Dickson*, 45 F.4th at 69 (quoting *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d at 1081).

[1551] Further, Order No. 1920's requirement that transmission providers revise their OATTs to include at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method separately and independently satisfies the APA's notice-and-comment requirements because courts have indicated that a final rule is a logical outgrowth of a proposal where, as here, an agency adopts only part of a proposal such that "the final rule [is] not wholly unrelated or surprisingly distant" from what the agency initially suggested. *Ariz. Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1297-1300 (D.C. Cir. 2000) (finding sufficient notice where agency first proposed that Indian tribes be required to meet the "same requirements" as states with respect to judicial review of permits issued pursuant to the Clean Air Act, but then adopted a final rule that exempted tribes from some, though not all, such requirements). Order No. 1920 is a logical outgrowth of the NOPR in this respect because the Commission adopted one of three proposed methods for complying with the requirement—i.e., part of the NOPR proposal—and the challenged provision therefore hews closely to the NOPR proposal such that it is "not wholly unrelated or surprisingly distant" from the NOPR proposal. *Id.*

adopt a number of modifications and clarifications herein to strengthen the states' role in those processes.[1552]

### 2. Substantive Issues

#### a. Order No. 1920 Requirements

618. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise their OATTs to include one or more *ex ante* cost allocation methods that apply to Long-Term Regional Transmission Facilities that are selected in the regional transmission plan for purposes of cost allocation (Long-Term Regional Transmission Cost Allocation Method).[1553]

619. In addition to the required Long-Term Regional Transmission Cost Allocation Method, Order No. 1920 permits transmission providers to revise their OATTs to include a State Agreement Process. However, the Commission found in Order No. 1920 that any State Agreement Process that transmission providers voluntarily propose to include in their OATTs would not comply with the requirements of Order No. 1920 unless Relevant State Entities indicate to the transmission provider that Relevant State Entities have agreed to that process during the Engagement Period.[1554] The Commission also found in Order No. 1920 that a State Agreement Process cannot be the sole method filed for cost

[1552] *See supra* Stakeholder Process and Transparency section; Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section; *infra* Consultation with Relevant State Entities After the Engagement Period section.

[1553] Order No. 1920, 187 FERC ¶ 61,068 at P 1291.

[1554] *Id.*; *see also id.* PP 1292, 1403.

allocation for Long-Term Regional Transmission Facilities.[1555] The Commission explained in Order No. 1920 that, if a State Agreement Process that transmission providers voluntarily include in their OATTs fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if the Commission ultimately finds the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop.[1556]

620. Order No. 1920 does not require transmission providers to obtain state agreement to a cost allocation method for any Long-Term Regional Transmission Facilities and states that the ultimate decision as to which Long-Term Regional Transmission Cost Allocation Method(s) to file on compliance, and whether to file a State Agreement Process to which Relevant State Entities have agreed, lies with transmission providers.[1557]

**b. Requests for Rehearing and Clarification**

621. On rehearing, a number of parties argue that the Commission's decision in Order No. 1920 to require transmission providers to file an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities will undermine Relevant State Entities' efforts to determine an alternative cost allocation method through a State Agreement

[1555] *Id.* PP 1292, 1361, 1404.

[1556] *Id.* PP 1291-1292.

[1557] *Id.* PP 1359, 1429; *see also id.* PP 1296, 1363.

Process.[1558] NARUC requests that the Commission adopt the NOPR proposal of mandatory agreement on filed method(s) and/or a State Agreement Process and eliminate the backstop *ex ante* method.[1559] NARUC argues that Order No. 1920's requirement that transmission providers have a backstop Long-Term Regional Transmission Cost Allocation Method in their OATTs undermines Relevant State Entities' negotiation of an alternative cost allocation method and turns such negotiations into a "check the box" exercise.[1560] NARUC asserts that allowing transmission providers to ignore or not even report on state input is the definition of an arbitrary and capricious action, and constitutes unreasonable decision making.[1561]

622. Ohio Commission Federal Advocate states that Order No. 1920 arbitrarily and capriciously requires an Engagement Period for states to participate in reaching a cost allocation agreement for Long-Term Regional Transmission Facilities while providing no assurance that it will amount to anything since the final rule allows the transmission provider to have the final say.[1562] Ohio Commission Federal Advocate argues that,

[1558] Designated Retail Regulators Rehearing Request at 35-36; Idaho Commission Rehearing Request at 5-6; NARUC Rehearing Request at 12-17; Ohio Commission Federal Advocate Rehearing Request at 8; Undersigned States Rehearing Request at 31-32; Wyoming Commission Rehearing Request at 2-4.

[1559] NARUC Rehearing Request at 12-17.

[1560] *Id.* at 16.

[1561] *Id.* at 15.

[1562] Ohio Commission Federal Advocate Rehearing Request at 7-8.

because of this, states ultimately have no authority on cost allocation for Long-Term Regional Transmission Facilities.[1563]

623. Designated Retail Regulators and Undersigned States state that Order No. 1920's requirement that transmission providers file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities eliminates the effectiveness of the State Agreement Process, as states are unlikely to agree to a negotiated cost allocation proposal under the State Agreement Process if the default *ex ante* cost allocation results in lower costs for those states.[1564] Designated Retail Regulators and Undersigned States argue that if states jointly agree on a cost allocation process, the rules should require the transmission provider to accept those cost allocation processes, subject to Commission approval.[1565]

624. Wyoming Commission states that the Commission's decision to remove the voluntary state agreement without a backstop reform in the final rule was a significant change from the NOPR, as the NOPR proposal would have allowed states to represent their public policy interests and, in the event of a conflict, prevent other states from exporting their policy decisions and an unreasonable share of related costs to nonconsenting neighbors. Wyoming Commission argues, however, that as a result of

[1563] *Id.* at 8.

[1564] Designated Retail Regulators Rehearing Request at 35-36; Undersigned States Rehearing Request at 31-32.

[1565] Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31.

reducing states' roles to mere stakeholders in the final rule, the Commission has forced states into agreeing to unjust and unreasonable cost allocations by defaulting to an *ex ante* cost allocation in lieu of requiring a voluntary agreement of the states as a prerequisite.[1566] Wyoming Commission asserts that a voluntary state agreement process is essential to avoid interfering with states' rights with respect to transmission planning and selection, and to prevent nonconsenting states from being "swept up" in their neighbors' identified public policy transmission projects.[1567]

625. Idaho Commission argues that by permitting, but not requiring, transmission providers to adopt a State Agreement Process in compliance with Order No. 1920, the states lack a meaningful opportunity to determine a reasonable cost allocation.[1568] Idaho Commission claims that the Commission's reasoning in not requiring a State Agreement Process is unsupported in the record and ignores that Relevant State Entities have statutory duties to ensure fair, just, and reasonable rates for customers.[1569] Idaho Commission further contends that requiring state agreement for cost allocation for Long-Term Regional Transmission Facilities, as the Commission proposed in the NOPR, would have allowed states to represent public policy interests and prevent other states from forcing policy decisions on nonconsenting neighbors. However, Idaho Commission

[1566] Wyoming Commission Rehearing Request at 2-3.

[1567] *Id.* at 3.

[1568] Idaho Commission Rehearing Request at 5-6.

[1569] *Id.*

asserts that as a result of Order No. 1920, states now have no meaningful opportunity to determine reasonable cost allocation and will be faced with cost allocation that violates the cost causation principle.[1570]

### c. Commission Determination

626. While we sustain the determination in Order No. 1920 that transmission providers in each transmission planning region must file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities, we believe that certain modifications adopted in this order help address, at least in part, concerns raised on rehearing by ensuring that the Commission may consider any Long-Term Regional Transmission Cost Allocation Methods supported by Relevant State Entities.[1571] We believe the balance struck in this order will assist the Commission, with the input of Relevant State Entities, in establishing just and reasonable Long-Term Regional Transmission Cost Allocation Methods that meet the requirements of Order No. 1920.

627. In Order No. 1920, the Commission required that, if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other entities authorized by Relevant State Entities to participate in a State Agreement Process,[1572] a transmission provider chooses not to file an agreed upon cost allocation

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[1570] *Id.*

[1571] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1572] Order No. 1920, 187 FERC ¶ 61,068 at P 1402 (noting that Relevant State Entities have the option to include the participation of other entities in a State Agreement

method, or if the Commission ultimately finds the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop. While we sustain the requirement to have a backstop Long-Term Regional Transmission Cost Allocation Method on file, we revise the portion of this requirement related to the transmission providers' choice as to whether to file Long-Term Regional Transmission Cost Allocation Methods and/or State Agreement Processes agreed to by Relevant State Entities, as discussed in further detail below.[1573]

628. Turning to the rehearing requests challenging the requirement to have an *ex ante* cost allocation method on file, we disagree with Wyoming Commission and Idaho Commission that this requirement forces states into agreeing to unjust and unreasonable cost allocations that allow states to foist the cost of their policy decisions on nonconsenting neighbors.[1574] Under the NOPR proposal, the Commission proposed that transmission providers in each transmission planning region file OATTs to include either (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which

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Process).

[1573] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1574] *See* Idaho Commission Rehearing Request at 5-6; Wyoming Commission Rehearing Request at 3.

one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof.[1575] Pursuant to the FPA, the Commission may accept only proposed rates, terms, and conditions that are just and reasonable. Therefore, the Commission could not accept a cost allocation method that would force states into agreeing to unjust and unreasonable cost allocations, and any just and reasonable cost allocation method must ensure that the costs of Long-Term Regional Transmission Facilities are allocated in a manner that is at least roughly commensurate with the estimated benefits.[1576]

629. We also disagree with arguments that the State Agreement Process will ultimately be a "check the box" exercise or that requiring an *ex ante* Long-Term Regional Transmission Cost Allocation Method otherwise limits the effectiveness of a State Agreement Process.[1577] Order No. 1920 places an affirmative obligation on transmission

[1575] NOPR, 179 FERC ¶ 61,028 at P 302.

[1576] Order No. 1920, 187 FERC ¶ 61,068 at PP 1510, 1515; *see, e.g.*, *ICC v. FERC I*, 576 F.3d at 476 ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."); Order No. 1000, 136 FERC ¶ 61,051 at P 690 ("If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.").

[1577] NARUC Rehearing Request at 16; Ohio Commission Federal Advocate Rehearing Request at 7-8; Designated Retail Regulators Rehearing Request at 35-36; Undersigned States Rehearing Request at 31-32.

providers to supply a forum for states to negotiate cost allocation,[1578] providing ample room for states to allocate costs in a manner that they agree to,[1579] and, as discussed below, in this order we require transmission providers to include in the transmittal or as an attachment to their compliance filing any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities agree upon.[1580] Relevant State Entities may structure the processes used to determine those cost allocation methods in a manner that would require a level of agreement of their choosing, including, as one potential option, unanimity.[1581] In this order, we also establish a requirement that transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.[1582] And as we have already discussed, transmission

[1578] Order No. 1920, 187 FERC ¶ 61,068 at PP 1354, 1356-1357.

[1579] *Id.* PP 1415-1416.

[1580] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1581] Order No. 1920, 187 FERC ¶ 61,068 at P 1418 ("We will not specify the level of agreement among Relevant State Entities or other entities that is necessary before a transmission provider files a cost allocation method derived from a State Agreement Process. As a state-led process, we believe that Relevant State Entities should have the ability to determine this important facet of their State Agreement Process.").

[1582] *See infra* Consultation with Relevant States Entities After the Engagement Period section.

providers shall develop a reasonable number of additional scenarios, when requested by Relevant State Entities, for the purposes of informing the application of Long-Term Regional Transmission Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es).[1583]

630. To the extent that Wyoming Commission argues that requiring an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities intrudes on states' rights with respect to transmission planning and selection, we disagree. We note that the D.C. Circuit held that requiring *ex ante* cost allocation methods under Order No. 1000 regional transmission planning does not intrude on state authority.[1584] We continue to find that Long-Term Regional Transmission Planning is a subset of regional transmission planning that closes specific gaps of the existing Order No. 1000 framework without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal.[1585]

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[1583] *See supra* Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section.

[1584] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-59, 62-64, 82-89; *id.* at 64 ((“[W]e hold that [Order No. 1000] does not interfere with the traditional state authority that is preserved by [FPA] Section 201 . . . .”).

[1585] Order No. 1920, 187 FERC ¶ 61,068 at P 256 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55-64 (rejecting arguments that the requirement to engage in regional transmission planning, as prescribed in Order No. 1000, exceeded the Commission's jurisdiction under FPA section 206, interfered with traditional state authority reserved under FPA section 201, or improperly interpreted and applied FPA section 202(a))).

631. With respect to the assertion that states are unlikely to agree to a negotiated cost allocation proposal under the State Agreement Process if the default *ex ante* cost allocation results in lower costs for those states, we note that Order No. 1920 provides Relevant State Entities with the opportunity to negotiate *ex ante* cost allocation methods in the first instance, and we take steps in this order to further enable states to do so.[1586] Further, states are likely to have an incentive to negotiate with other states in order to ensure timely and efficient development of Long-Term Regional Transmission Facilities that benefit their ratepayers, but would not be developed without the support of other states. We find that the opportunity for Relevant State Entities to negotiate *ex ante* cost allocation methods in the first instance and agree to a State Agreement Process, coupled with the benefits of certainty provided by a backstop *ex ante* cost allocation method, strike a reasonable balance, and we otherwise sustain, as explained in greater detail below, the Commission's finding in Order No. 1920 that requiring transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1587]

632. We disagree with Idaho Commission's contention that Order No. 1920 denies Relevant State Entities any meaningful opportunity to determine reasonable cost

[1586] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section.

[1587] Order No. 1920, 187 FERC ¶ 61,068 at P 1293.

allocation methods.[1588] We recognize the critical role that states play in regional transmission planning and that Relevant State Entities have their own statutory obligations. As discussed in Order No. 1920, and expanded upon here,[1589] we are placing an affirmative obligation on transmission providers to provide a meaningful opportunity for Relevant State Entities to share their views on cost allocation during the Engagement Period, during subsequent implementation of a State Agreement Process to which the Relevant State Entities have agreed that has been filed by a transmission provider and accepted by the Commission,[1590] and, as described herein, before future cost allocation amendments.[1591] Relevant State Entities therefore have a meaningful opportunity to participate in cost allocation decisions related to Long-Term Regional Transmission Facilities.

633. We continue to find that if transmission providers were to rely solely on a State Agreement Process to determine the cost allocation for Long-Term Regional Transmission Facilities and that process did not result in agreement on a cost allocation method, there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term

[1588] Idaho Commission Rehearing Request at 5-6.

[1589] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section.

[1590] Order No. 1920, 187 FERC ¶ 61,068 at P 1296.

[1591] *See infra* Consultation with Relevant State Entities After the Engagement Period section.

Transmission Needs.[1592] As a result, these selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized.[1593] Furthermore, we continue to find that, if these selected Long-Term Regional Transmission Facilities were not ultimately built, transmission providers would likely rely on relatively inefficient or less cost-effective transmission facilities to address the identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates.[1594]

634. In addition, we are concerned that a state-agreement requirement could lead to a situation in which a transmission project was planned based on benefits that it provides to customers in several states, and that, if one or more of those states declined to voluntarily agree to a cost allocation method, it would raise free-ridership concerns.[1595] For that reason, sole reliance on a State Agreement Process has the potential to suffer from the

[1592] Order No. 1920, 187 FERC ¶ 61,068 at P 1293.

[1593] *Id.*

[1594] *Id.*

[1595] *See El Paso Elec. Co. v. FERC*, 76 F.4th at 361-63 ("No amount of emphasizing other competing interests permits FERC to sacrifice the foundational principle of cost-causation by refusing to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits." (citations omitted)); Order No. 1000, 136 FERC ¶ 61,051 at P 535 ("[If] the Commission could not address free rider problems associated with new transmission investment, [] it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory.").

same flaws that led the Commission to require *ex ante* cost allocation for selected regional transmission facilities in Order No. 1000, as the allocation of transmission costs can be contentious and prone to litigation in multi-state transmission planning regions.[1596] The level of certainty for transmissions providers in having a Long-Term Regional Transmission Cost Allocation Method on file, even when a State Agreement Process is used, remains critical to the development of needed Long-Term Regional Transmission Facilities.[1597]

### B. Requirements Concerning Relevant State Entities

#### 1. Requested Requirement to Obtain the Agreement of Relevant State Entities

##### a. Order No. 1920 Requirements

635. In Order No. 1920, the Commission declined to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Instead, the Commission modified the NOPR proposal to establish a six-month time period (Engagement Period), during which transmission providers must, among other requirements, provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.[1598]

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[1596] Order No. 1920, 187 FERC ¶ 61,068 at P 1293 (citation omitted).

[1597] *Id.*

[1598] *Id.* P 1354.

**b. Requests for Rehearing and Clarification**

636. Undersigned States and Designated Retail Regulators argue that the Engagement Period is not a "fair replacement of a requirement for regulator consent" because Order No. 1920 does not require transmission providers to propose on compliance a Long-Term Regional Transmission Cost Allocation Method agreed to by the states.[1599] Undersigned States and Designated Retail Regulators further argue that Order No. 1920's lack of a requirement for transmission providers to obtain the consent of retail regulators on the cost allocation method(s) that apply to Long-Term Regional Transmission Facilities usurps state authority because it enables the ratepayers of non-consenting states to be assessed the costs of the public policy projects of other states and speculative investment based on conjecture about future resource trends.[1600] Designated Retail Regulators argue that existing regulator organizations such as OMS "may not be the best forums to confect state agreements" because the "authority to reach agreement on cost allocation rests in each State" and cannot be delegated to such organizations in order to reach general consensus on issues.[1601]

[1599] Designated Retail Regulators Rehearing Request at 36; Undersigned States Rehearing Request at 32.

[1600] Designated Retail Regulators Rehearing Request at 36-39; Undersigned States Rehearing Request at 32-35.

[1601] Designated Retail Regulators Rehearing Request at 38.

### c. Commission Determination

637. While we sustain our decision not to adopt the NOPR proposal and instead establish the Engagement Period for cost allocation negotiations, we believe that certain modifications in this order help address, at least in part, the concerns raised by Designated Retail Regulators and Undersigned States by providing additional opportunities for Relevant State Entities to help establish just and reasonable cost allocation methods for Long-Term Regional Transmission Facilities.[1602]

638. Turning to Designated Retail Regulators' and Undersigned States' arguments, the Commission did not propose in the NOPR to require transmission providers to obtain the consent of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Rather, the Commission proposed to require transmission providers to seek the agreement of Relevant States Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[1603] In Order No. 1920, the Commission did not adopt the requirement for

[1602] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

[1603] Order No. 1920, 187 FERC ¶ 61,068 at P 1354 ("We decline to adopt the NOPR proposal to require transmission providers to *seek the agreement* of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities." (emphasis added)). We address arguments concerning the Commission's decision not to require transmission providers to seek the agreement of Relevant State Entities in the Requests Arguing the Engagement Period is Inferior to a Requirement that Transmission Providers

transmission providers to seek the agreement of Relevant State Entities (while affording transmission providers flexibility in the process by which they seek agreement from the Relevant State Entities) and instead adopted a requirement for transmission providers to provide a forum for states to meaningfully participate in negotiating cost allocation methods.[1604]

639. With respect to requests that we *require* agreement of state regulators for any cost allocation method for Long-Term Regional Transmission Facilities, we continue to find that the views of state regulators regarding the appropriate cost allocation approach are important, but ultimately the transmission provider is the public utility that must respond and comply with Order No. 1920.[1605] Furthermore, the Commission has a statutory responsibility to review the compliance filings from transmission providers to ensure that any proposed cost allocation is just and reasonable and not unduly discriminatory or preferential, and Order No. 1920 recognizes these statutory roles.[1606] Nonetheless, we reiterate that robust state engagement can valuably inform a cost allocation approach and, as discussed further below, we take steps in this order to further that engagement.

640. In response to Designated Retail Regulators' and Undersigned States' argument that Order No. 1920's lack of a requirement for transmission providers to obtain the

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Seek the Agreement of Relevant State Entities section below.

[1604] *See id.* PP 1354, 1357.

[1605] *Id.* P 1363.

[1606] *Id.*

consent of states on the cost allocation method(s) that apply to Long-Term Regional Transmission Facilities enables the ratepayers of non-consenting states to be assessed the costs of other states' public policies and speculative investment,[1607] in addition to the steps to further state engagement taken herein, we note that all cost allocation methods for Long-Term Regional Transmission Facilities, including Long-Term Regional Transmission Cost Allocation Methods and cost allocation methods resulting from State Agreement Processes, must allocate the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with the estimated benefits, consistent with legal precedent.[1608] We find that this requirement addresses Designated Retail Regulators' and Undersigned States' concern that Order No. 1920's requirements will result in non-consenting states paying for costs they did not cause.

641. In response to Designated Retail Regulators' assertion that the "authority to reach agreement on cost allocation rests in each State" and that this authority cannot be "delegated to organizations that States participate in to attempt to reach general consensus on issues,"[1609] we note that Order No. 1920 did not require transmission providers to use existing mechanisms for state involvement in regional transmission planning and cost allocation processes, such as the SPP Regional State Committee and

[1607] Designated Retail Regulators Rehearing Request at 37-38; Undersigned States Rehearing Request at 33.

[1608] *See supra* P 628 n.1577.

[1609] *See* Designated Retail Regulators Rehearing Request at 38.

OMS, as a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[1610] In fact, Order No. 1920 specified that it is Relevant State Entities – and not transmission providers – who may choose to use such an existing mechanism to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[1611] Similarly, the Commission left to the Relevant State Entities participating in the Engagement Period matters including what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement.[1612]

### 2. Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods

#### a. Order No. 1920 Requirements

642. In Order No. 1920, the Commission found that, if the Relevant State Entities participating in an Engagement Period agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and provide that Method(s) and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement, the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. The Commission noted, however, that the ultimate decision as to

[1610] Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1611] *Id.*

[1612] *Id.* P 1360.

whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.[1613] In addition, the Commission found that its directives in Order No. 1920 regarding the development of a State Agreement Process and any cost allocation methods to which the Relevant State Entities agree pursuant to that process do not alter existing FPA section 205 filing rights that would govern subsequent filings regarding the cost allocation for Long-Term Regional Transmission Facilities.[1614] The Commission did not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATT.[1615]

**b. Requests for Rehearing and Clarification**

643. NARUC, PJM States, Designated Retail Regulators, Undersigned States, and West Virginia Commission request rehearing of Order No. 1920's decision not to require

[1613] *Id.* PP 1359, 1363.

[1614] *Id.* P 1430 ("We further clarify that unless voluntarily waived, a transmission provider retains its FPA section 205 filing rights to submit an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities at any time, consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO.") (citation omitted).

[1615] *Id.* PP 1359, 1429.

transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period.[1616] NARUC argues that Order No. 1920 "arbitrarily and without adequate explanation removes protections proposed in the NOPR for states and their ratepayers by not requiring [t]ransmission [providers] to incorporate state consensus to cost allocation methods for filing as part of the OATT."[1617] PJM States argue that, absent such a requirement, state engagement in the development of cost allocation methods for Long-Term Regional Transmission Facilities is not likely to materialize. PJM States argue that, by contrast, incenting state agreement (and the filing of that agreement) makes it more likely that Order No. 1920's goals are met, as a state-agreed upon cost allocation method has a lower burden of proof than a transmission provider filing without state agreement.[1618] West Virginia Commission agrees with PJM States and argues that the Commission should either require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period or "grant the States 205 filing rights as it pertains to State-agreed cost allocation methods."[1619]

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[1616] NARUC Rehearing Request at 12; PJM States Rehearing Request at 2-3; Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31; West Virginia Commission Rehearing Request at 13-14.

[1617] NARUC Rehearing Request at 12.

[1618] PJM States Rehearing Request at 2-3 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 1469, 1472, 1476).

[1619] West Virginia Commission Rehearing Request at 13-14.

644. PIOs, PJM States, and NARUC request clarification that, where a particular cost allocation method garnered state support during the Engagement Period and the transmission provider elects not to adopt that method in its compliance filing, the transmission provider must include the states' preferred cost allocation method in its compliance filing and explain why that method was not used.[1620] West Virginia Commission requests the same clarification in the alternative to its request that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period.[1621] West Virginia Commission requests that the Commission require transmission providers to include the states' preferred cost allocation method "for informational purposes."[1622] NARUC further requests that the Commission clarify that transmission providers' compliance filings must also include a general description of the discussions during the Engagement Period, including transmission providers' outreach to Relevant State Entities.[1623] Similarly, NARUC, PJM States, and Virginia and North Carolina Commissions request that the Commission clarify that transmission providers must disclose the extent to which states agreed or disagreed with the filed cost allocation method.[1624] PIOs also request that

[1620] NARUC Rehearing Request at 17-18; PIOs Rehearing Request at 55-57; PJM States Rehearing Request at 7-8.

[1621] West Virginia Commission Rehearing Request at 9.

[1622] *Id.*

[1623] NARUC Rehearing Request at 17-18.

[1624] *Id.* at 17; PJM States Rehearing Request at 7; Virginia and North Carolina

the Commission clarify that: (1) transmission providers must "clearly disclose and explain the outcome" of the Engagement Period; (2) the Commission will carefully evaluate the existence of a state agreement regarding cost allocation and any departure from that agreement in reviewing cost allocation methods proposed by transmission providers on compliance; and (3) transmission providers must explain how their chosen cost allocation methods are just and reasonable and not unduly discriminatory or preferential. PIOs contend that their requested clarifications would offer states additional confidence that participation in the Engagement Period will be meaningful.[1625]

645. NESCOE requests rehearing of Order No. 1920's decision to not require transmission providers to file states' preferred cost allocation method along with transmission providers' own preferred cost allocation method. NESCOE argues that because states are not public utilities, absent language in the transmission providers' organizational documents or OATTs, states are unable to file cost allocation methods themselves. NESCOE argues that "[r]elegating states to commenting on a transmission provider's cost allocation filing does not enable the states to put before the Commission their preferred cost allocation method; rather, it shifts the burden to states to show that the transmission provider's FPA section 205 filing is not just and reasonable."[1626] NESCOE contends that Order No. 1920 envisions that the only path for states to have their

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Commissions Rehearing Request at 10.

[1625] PIOs Rehearing Request at 54-57.

[1626] NESCOE Rehearing Request at 14-15.

preferred cost allocation method approved would be through a complaint proceeding in which states would bear the burden of first proving that a transmission provider's Commission-approved cost allocation method is unjust and unreasonable.[1627] NESCOE argues that requiring each transmission provider to file states' preferred cost allocation method alongside its own would comport with precedent holding that the Commission may not require transmission providers "'to cede rights expressly given to them' in FPA section 205."[1628] In the alternative, NESCOE requests that the Commission strongly encourage transmission providers to "voluntarily codify existing or new approaches on compliance" that would facilitate transmission providers' filing of alternative region-wide state agreement on cost allocation, such as the approaches used in the NYISO and SPP regions.[1629] NESCOE opines that "[i]ncluding the state-agreed upon cost allocation method in a transmission provider's section 205 filing is a lawful and rational means to effectuate in a concrete way the respect for the state role the Commission articulates."[1630]

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[1627] *Id.* Vermont Commission states that it supports the NESCOE Rehearing Request, including strengthening the state role in all phases of Long-Term Regional Transmission Planning, and specifically cost allocation. Vermont Commission Rehearing Request at 1-2.

[1628] NESCOE Rehearing Request at 15 (quoting *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9).

[1629] *Id.* at 15-16 (citing NESCOE NOPR Initial Comments at 69-70 (citing *N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,040, at P 119 (2015) (*NYISO*); SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), § 7.2)).

[1630] *Id.* at 16.

646. Harvard ELI requests that the Commission grant rehearing by requiring transmission providers to revise their OATTs to include a process for filing all regional cost allocation methods approved by Relevant State Entities.[1631] Harvard ELI contends that, by not requiring transmission providers to file all cost allocation methods agreed to by Relevant State Entities, Order No. 1920 fails to remedy unjust and unreasonable cost allocation processes.[1632] Harvard ELI argues that such a requirement would not violate the D.C. Circuit's holding in *Atlantic City* because it would neither "deny utilities their right to unilaterally file rate and term changes" nor "force public utilities to file particular rates."[1633] Harvard ELI argues that, because the Commission "has authority to approve utility filing rights arrangements under FPA section 205," it also has the authority under FPA section 206 to order changes to filing processes and may do so here to require transmission providers to file all cost allocation methods approved by the Relevant State Entities.[1634] In the alternative, Harvard ELI requests that the Commission clarify that it did not intend to imply that it lacks authority under FPA section 206 to amend the *pro*

[1631] Harvard ELI Rehearing Request at 1-3.

[1632] *Id.* at 6 (stating that existing cost allocation requirements do not provide a "dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods" (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 126)).

[1633] *Id.* at 4-5 (alteration omitted) (quoting *Atl. City Elec. Co. v. FERC*, 295 F.3d at 10).

[1634] *Id.* at 4.

*forma* OATT to include a process for filing all regional cost allocation methods approved by Relevant State Entities.[1635]

647. NARUC requests that the Commission provide a mechanism to ensure that transmission providers "remain in compliance with the requirement to include [R]elevant [S]tate [E]ntities in cost allocation for Long-Term Regional Transmission Facilities."[1636] NARUC asserts that the Commission should either require transmission providers to periodically open new Engagement Periods or require transmission providers to file a modification to their OATTs if states reach the requisite agreement on a different cost allocation method than that reflected in the transmission providers' OATTs.[1637]

648. PIOs request clarification that transmission providers may, in their compliance filings, voluntarily commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation method will be put before the Commission for approval.[1638]

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[1635] *Id.* at 1, 8-9.

[1636] NARUC Rehearing Request at 21-22.

[1637] *Id.* In the Consultation with Relevant State Entities After the Engagement Period section below, we discuss NARUC's request that the Commission require transmission providers to periodically open a new negotiation period with Relevant State Entities concerning cost allocation for Long-Term Regional Transmission Facilities.

[1638] PIOs Rehearing Request at 55-56.

### c. Commission Determination

649. As the Commission recognized in Order No. 1920, and we reiterate in this order, it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes.[1639] At the same time, the Commission has an independent responsibility to ensure that those cost allocation methods conform to the cost causation principle and are otherwise just and reasonable and not unduly discriminatory or preferential.

650. To address these considerations and the concerns raised on rehearing, we simultaneously (1) expand Relevant State Entities' opportunities to inform and provide alternatives to the transmission providers' proposed Long-Term Regional Transmission Cost Allocation Method, and (2) sustain Order No. 1920's determination that transmission providers retain the right to determine which cost allocation methods for Long-Term Regional Transmission Facilities they will propose on compliance. Accordingly, while we decline rehearing parties' requests that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, we take steps to ensure that the Commission may consider the Relevant State Entities' preferred Long-Term Regional Transmission

[1639] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 1415.

Cost Allocation Method(s) and/or State Agreement Process, to the extent those differ from the Method(s) filed by transmission providers on compliance.

651. To that end, we set aside Order No. 1920, in part, and require that when Relevant State Entities notify transmission providers by the deadline for communicating agreement[1640] that they agree on a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process resulting from the Engagement Period, the transmission providers must include that method or process in the transmittal or as an attachment to their compliance filing, even if the transmission providers propose a different Long-Term Regional Transmission Cost Allocation Method or do not propose to adopt a State Agreement Process. We further direct transmission providers to include in the transmittal or as an attachment to their compliance filings any information that Relevant State Entities provide to them regarding the state negotiations during the Engagement Period. We also set aside Order No. 1920, in part, to require that, upon the request of Relevant State Entities, transmission providers must facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities.

[1640] Order No. 1920 requires that transmission providers in each transmission planning region provide notice, such as on its OASIS page or public website, of the deadline for Relevant State Entities to communicate their agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, and this deadline must be no earlier than the end date of the Engagement Period. *Id.* P 1356.

652. At the outset, in response to arguments concerning the Commission's authority to impose the various cost allocation requirements proposed by parties on rehearing,[1641] we reiterate that the Commission in Order No. 1920 determined that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential under FPA section 206.[1642] The Commission thus had both the authority and responsibility to "determine the just and reasonable . . . practice . . . to be thereafter observed and in force,"[1643] consistent with Order No. 1920's findings. Pursuant to its authority under FPA section 206, the Commission required transmission providers to submit on compliance an *ex ante* cost allocation method. This compliance filing submitted pursuant to FPA section 206 is not an FPA section 205 filing,[1644] and is thus distinct from any FPA section 205 filing that a transmission provider might file in the future following compliance to propose a change to its cost allocation method(s) for Long-Term Regional Transmission Facilities.[1645]

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[1641] *E.g.*, Harvard ELI Rehearing Request at 4; NESCOE Rehearing Request at 15.

[1642] Order No. 1920, 187 FERC ¶ 61,068 at PP 113-114; *supra* The Overall Need for Reform section.

[1643] 16 U.S.C. 824e(a).

[1644] *See ISO New England Inc.*, 165 FERC ¶ 61,202 (2018), *order on reh'g*, 173 FERC ¶ 61,204, at P 8 (2020) (clarifying that the Commission would review ISO-NE's proposed tariff revisions as a new FPA section 205 filing, rather than a compliance filing, because the Commission had not previously made "a finding that ISO-NE's tariff was unjust and unreasonable without such revisions, a necessary precursor to the Commission considering ISO-NE's tariff revisions as a compliance filing setting forth a proposed replacement rate").

[1645] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1430. As discussed below in the

653. We believe the balance struck herein should address, at least in part, the concerns driving the rehearing requests of NARUC, PJM States, Designated Retail Regulators, Undersigned States, and West Virginia Commission, who request that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, and NESCOE, which argues that the Commission should require transmission providers to propose on compliance Relevant State Entities' preferred cost allocation method along with transmission providers' preferred cost allocation method.[1646] While we continue to find that robust state engagement is valuable to informing cost allocation,[1647] we also recognize transmission providers, subject to Commission oversight, remain ultimately responsible for transmission planning,[1648] which we find is fundamentally linked with cost allocation.[1649]

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Consultation with Relevant State Entities After the Engagement Period section, we adopt, as part of this rule, a requirement that transmission providers revise their OATTs to add a requirement that they consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

[1646] NARUC Rehearing Request at 12; NESCOE Rehearing Request at 14-15; PJM States Rehearing Request at 2-3; Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31; West Virginia Commission Rehearing Request at 13-14.

[1647] Order No. 1920, 187 FERC ¶ 61,068 at P 1363.

[1648] *Id.* *See also* Order No. 1000, 136 FERC ¶ 61,051 at P 153; Order No. 890, 118 FERC ¶ 61,119 at P 454.

[1649] Order No. 1000, 136 FERC ¶ 61,051 at P 559 ("[T]here is a fundamental link between cost allocation and planning, as it is through the planning process that benefits,

Consistent with this responsibility, while reiterating the balance the Commission seeks to strike in this order regarding the role of Relevant State Entities, we decline to require transmission providers, on compliance, to propose to adopt a State Agreement Process or Long-Term Regional Transmission Cost Allocation Method to which Relevant State Entities agreed, particularly if transmission providers prefer an alternative approach to cost allocation.

654. However, we are persuaded by PIOs', PJM States', and NARUC's arguments that the Commission should consider any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement process to which the Relevant State Entities agree. We agree that the Commission should require transmission providers to include in the transmittal of their compliance filings any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process to which the Relevant State Entities agreed but that transmission providers elect not to propose to comply with Order No. 1920.[1650] Therefore, we set aside Order No. 1920, in part, and require that, when Relevant State Entities communicate to transmission providers by the deadline for communicating agreement that they agree on a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process resulting from the Engagement Period, the transmission providers must include that method or process in the transmittal

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which are central to cost allocation, can be assessed.").

[1650] *See* NARUC Rehearing Request at 17-18; PIOs Rehearing Request at 55-57; PJM States Rehearing Request at 7-8.

or as an attachment to their compliance filings, even if the transmission providers propose to adopt a different Long-Term Regional Transmission Cost Allocation Method or do not propose to revise their tariffs to include a State Agreement Process.[1651] We continue to decline to define what constitutes agreement among Relevant State Entities,[1652] but we note that, at the choosing of the Relevant State Entities in a transmission planning region, existing relevant state committee processes may guide Relevant State Entities in defining what constitutes agreement, such as the processes of OMS and NESCOE.

655. We are also persuaded by NARUC's, PIOs', PJM States', and Virginia and North Carolina Commissions' arguments that the Commission should require transmission providers to provide additional information related to Relevant State Entities' participation in the Engagement Period even when transmission providers propose on compliance a separate cost allocation method and/or decline to propose a State Agreement Process,[1653] and we therefore further direct transmission providers to include

[1651] We clarify that, under this approach, the transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments, whether they decide to propose the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process or a different Long-Term Regional Transmission Cost Allocation Method. The requirement to include Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process as an addition to the compliance filing does not constitute a "proposal" from the transmission provider.

[1652] Order No. 1920, 187 FERC ¶ 61,068 at P 1360.

[1653] NARUC Rehearing Request at 17; PIOs Rehearing Request at 54-57; PJM States Rehearing Request at 7; Virginia and North Carolina Commission Rehearing Request at 10.

in the transmittal or as an attachment to their compliance filings any information that any Relevant State Entities provide to them regarding the state negotiations during the Engagement Period. As part of this requirement, we clarify that transmission providers must include any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing. We expect that the information that Relevant State Entities provide to transmission providers could include, for example, a description of the discussions that took place at the Engagement Period forum for negotiation and whether each Relevant State Entity agreed or disagreed with the cost allocation method proposed on compliance. However, we decline to require transmission providers to independently characterize this information. For example, we do not require transmission providers to separately characterize Relevant State Entities' agreement or independently justify Relevant State Entities' preferred Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process. We find that a requirement for transmission providers to include in the transmittal or as an attachment to their compliance filings the information received from any Relevant State Entities during the Engagement Period will sufficiently capture the results of the Engagement Period.

656. Furthermore, upon review of the requests for rehearing and clarification about the Engagement Period, we also believe that Relevant State Entities would benefit from the assistance of transmission providers in some cases, as transmission providers may have more experience with the transmission providers' OATTs and with the Commission's

processes and precedent. Therefore, we set aside Order No. 1920, in part, and now include a requirement that upon the request of Relevant State Entities, transmission providers must facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities.

657. We find that these additional requirements will allow the Commission to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period.[1654] Furthermore, given that we direct these facilitation and informational requirements on compliance pursuant to the Commission's authority under FPA section 206, we find that these requirements do not implicate or infringe upon transmission providers' filing rights under FPA section 205.

658. When acting under FPA section 206, the Commission's statutory burden is to establish *a* just and reasonable and not unduly discriminatory replacement rate that is supported by substantial evidence.[1655] The statute does not necessarily require the Commission to adopt the transmission provider's proposal on compliance, even if that proposal complies with the final rule's requirements. Rather, the Commission need only select a replacement rate that complies with the final rule and that is adequately supported in the record, and then intelligibly explain the reasons for its choice.[1656]

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[1654] Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1655] 16 U.S.C. 824e; 16 U.S.C 825*l*(b).

[1656] *See Entergy Ark., LLC v. FERC*, 40 F.4th 689, 701–02 (D.C. Cir. 2022) (noting that the Commission "is not required to choose the best solution, only a

659. We recognize that the Commission generally does not consider alternate compliance proposals other than those filed by the relevant public utility (here, the transmission provider).[1657] Nevertheless, as the Commission explained in Order No. 1920, and as we reiterate on rehearing, there are "good reasons" for considering such alternatives here with respect to cost allocation under Order No. 1920.[1658] States play a unique role in Long-Term Regional Transmission Planning, as their laws, regulations, and policies drive the need for Long-Term Regional Transmission Facilities,[1659] and they typically will have responsibility to consider and approve the siting, permitting, and construction of Long-Term Regional Transmission Facilities selected in a regional transmission plan. As such, states affect whether Long-Term Regional Transmission Facilities are timely, efficiently, and cost-effectively developed such that customers actually receive the benefits associated with the selection of more efficient or cost-effective transmission solutions.[1660] We further find that, given the inherent uncertainty

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reasonable one") (first quoting *Petal Gas Storage, LLC v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); and then quoting *EPSA*, 577 U.S. at 295).

[1657] *See, e.g.*, *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134, at P 117 n.175 (2020); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 115 (2007); *ANR Pipeline Co.*, 110 FERC ¶ 61,069, at P 49 (2005).

[1658] *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 515.

[1659] *Supra* Categories of Factors section.

[1660] Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362-1364, 1404, 1407, 1410-1411, 1415, 1477, 1515.

involved in planning to meet Long-Term Transmission Needs,[1661] state-developed cost allocation methods and State Agreement Process take on heightened importance. This means that the Commission will consider the entire record – including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal – when setting the replacement rate. Specifically, when the Commission reviews transmission providers' compliance filings, the Commission is not required to accept a cost allocation proposal from a transmission provider simply because it may comply with Order No. 1920. Instead, the Commission may adopt any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920.[1662]

660. We believe Order No. 1920, as modified here on rehearing, strikes a reasonable balance between, on the one hand, recognizing the rights and responsibilities of the Commission and transmission providers over regional transmission planning and, on the other, the states' critical interests in the resulting Long-Term Regional Transmission Facilities and how the costs associated with those facilities will be allocated. We also believe that this balance, including the requirement that transmission providers consult

[1661] *Id.* P 227.

[1662] We believe that these findings address NESCOE's arguments that Order No. 1920's cost allocation requirements "[r]elegat[ed] states to commenting on a transmission provider's cost allocation filing," or that the "only path the Commission envision[ed] for approval of the states' cost allocation method would be through the vehicle of a complaint." NESCOE Rehearing Request at 14.

with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process,[1663] addresses, at least in part, concerns underlying arguments by Harvard ELI and NARUC that the Commission should establish a prospective mechanism through which transmission providers would be required to file for Commission approval any cost allocation methods approved by Relevant State Entities[1664] or if states reach the requisite agreement on a different cost allocation method than that reflected in the OATT then on file.[1665]

661. Nonetheless, consistent with our findings above with respect to requests that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, we decline to adopt Harvard ELI's and NARUC's proposals. Transmission planning is the tariff obligation of each transmission provider and transmission providers retain, subject to Commission oversight, responsibility for regional transmission planning, including Long-Term

[1663] *See infra* Consultation with Relevant State Entities After the Engagement Period section.

[1664] Harvard ELI Rehearing Request at 1-3. Because we are unpersuaded by Harvard ELI's request for rehearing in this respect, we find it unnecessary to address Harvard ELI's request for clarification in the alternative that FPA section 206 provides the Commission the authority to amend the *pro forma* OATT to include a process for filing all cost allocation methods approved by Relevant State Entities. *Id.* at 8.

[1665] NARUC Rehearing Request at 21-22.

Regional Transmission Planning, as well as complying with the obligations of Order No. 1920.[1666] We disagree with Harvard ELI's contention that Order No. 1920's cost allocation requirements fail to remedy unjust and unreasonable cost allocation processes because Order No. 1920 does not require transmission providers to file all cost allocation methods approved by Relevant State Entities.[1667] As discussed below,[1668] we find that the Engagement Period established in Order No. 1920 provides the "dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods"[1669] that the Commission recognized was absent from existing cost allocation requirements. We further find that, combined with existing opportunities for state engagement in the development of regional cost allocation methods along with those established herein,[1670] Order No. 1920's cost allocation requirements remedy the

[1666] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 996 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 153), 1363; *see also* Order No. 890, 118 FERC ¶ 61,119 at P 454 ("[T]ransmission planning is the tariff obligation of each transmission provider."). To the extent that West Virginia Commission, in stating that the Commission should "grant the States 205 filing rights as it pertains to State-agreed cost allocations," is requesting that the Commission confer filing rights to states under FPA section 205, West Virginia Commission does not explain the authority or legal theory upon which it believes the Commission could do so. West Virginia Commission Rehearing Request at 14.

[1667] Harvard ELI Rehearing Request at 6-7.

[1668] *See* Design and Operation of the Engagement Period section.

[1669] Order No. 1920, 187 FERC ¶ 61,068 at P 126.

[1670] *See supra* P 654; *infra* Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

unjust, unreasonable, and unduly discriminatory or preferential existing regional cost allocation requirements.

662. In response to PIOs' request that the Commission clarify that transmission providers may voluntarily commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation will be put before the Commission for approval,[1671] and NESCOE's request that the Commission strongly encourage transmission providers to commit to such processes,[1672] we reiterate that transmission providers may voluntarily adopt a process in their OATTs, whether it be a State Agreement Process or another Commission-approved process, under which they commit to file with the Commission pursuant to FPA section 205 any cost allocation method that garners state agreement subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920.[1673] We also agree with NESCOE's request and strongly encourage transmission providers to commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation will be put before the Commission for approval. As discussed further below, such a process could satisfy the requirement we establish for

[1671] PIOs Rehearing Request at 55-56.

[1672] NESCOE Rehearing Request at 15-16.

[1673] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1412 n.3013 ("[T]ransmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.").

transmission providers to consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.[1674]

### C. Design and Operation of the Engagement Period

#### 1. Logical Outgrowth

##### a. NOPR Proposals

663. To implement the NOPR proposal to require transmission providers to include in their OATTs either a Long-Term Regional Transmission Cost Allocation Method or a State Agreement Process, or a combination thereof, the Commission proposed to require transmission providers to "seek the agreement" of relevant state entities regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning and to revise their OATTs to include the method or methods.[1675] The Commission additionally proposed to afford transmission providers flexibility in the process by which they seek agreement from the Relevant State Entities.[1676] The Commission stated that the proposed reforms would enable Relevant State Entities who

[1674] *See Infra* Consultation with Relevant State Entities After the Engagement Period section.

[1675] NOPR, 179 FERC ¶ 61,028 at PP 278, 303, 305, 308.

[1676] *Id.* P 306.

seek greater involvement in cost allocation for Long-Term Regional Transmission Facilities an opportunity to do so.[1677]

664. In the NOPR, the Commission also proposed to require transmission providers to establish a process, detailed in their OATTs, to provide a state or states (in multi-state transmission planning regions) a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method that would otherwise apply. The Commission proposed that, during that time period, if a state or all states within the transmission planning region in which the selected regional transmission facility would be located unanimously agree on an alternate cost allocation method, the transmission provider may elect to file it with the Commission.[1678] The Commission explained that providing states with a time period to propose alternate cost allocation methods could help facilitate the timely development of more efficient or cost-effective regional transmission facilities.[1679]

### b. Order No. 1920 Requirements

665. In Order No. 1920, the Commission declined to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities regarding the cost allocation method to be applied to Long-Term Regional Transmission

[1677] *Id.* P 314.

[1678] *Id.* P 319.

[1679] *Id.* P 321.

Facilities.[1680] Instead, the Commission established a six-month Engagement Period, during which transmission providers must, among other things, provide a forum for the negotiation of a Long-Term Regional Transmission Cost Allocation Methods(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities, and required transmission providers to explain on compliance how they complied with the six-month Engagement Period requirements.[1681] The Commission also declined to adopt the NOPR proposal to require transmission providers to establish a process, detailed in their OATTs, to provide a state or states (in multi-state transmission planning regions) a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method that would otherwise apply.[1682]

### c. Requests for Rehearing and Clarification

666. NRECA asserts that the requirement in Order No. 1920 for transmission providers to file a Long-Term Regional Transmission Cost Allocation Method with or without the agreement of Relevant State Entities, and to conduct a six-month Engagement Period to provide a forum for negotiation of Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process, is not a logical outgrowth of the NOPR

[1680] Order No. 1920, 187 FERC ¶ 61,068 at P 1354.

[1681] *Id.* PP 1354, 1357.

[1682] *Id.* P 1456.

proposal to require the transmission providers in a transmission planning region to seek agreement with Relevant State Entities as to a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process.[1683] Undersigned States argue that the NOPR "placed the states in a central role in the regulatory structure by requiring transmission providers to seek the agreement of states for cost allocation," but that Order No. 1920 "removed the requirement that states give their consent on cost allocation," which is "'surprisingly distant' from the states' role in the NOPR and is in essence a new rule that requires new opportunities for comment and input."[1684] West Virginia Commission argues that Order No. 1920 "effectively exceeds the substantive notice of the NOPR" by removing realistic opportunities for states to work cooperatively on cost allocation agreements that will be proposed as *ex ante* cost allocation methods and adding "an ineffective substitute for seeking state agreement for cost allocation" by establishing the six-month Engagement Period.[1685] Utah Commission similarly contends that the elimination of any requirement that a state agree to a cost allocation that its residents must bear, no matter how detached the states' residents are from causing the associated

[1683] NRECA Rehearing Request at 17-18.

[1684] Undersigned States Rehearing Request at 38 (quoting *Int'l Union, United Mine Workers of Am.*, 407 F.3d at 1259-60).

[1685] West Virginia Commission Rehearing Request at 3.

costs or from the associated policies, does not constitute a logical outgrowth of the NOPR.[1686]

### d. Commission Determination

667. As discussed elsewhere in this rule, we take steps in this order to expand Relevant State Entities' opportunities to inform and, as needed, provide alternatives to, transmission providers' proposed Long-Term Regional Transmission Cost Allocation Method(s). Therefore, while we disagree with rehearing parties' arguments that the Engagement Period and associated reforms are not a logical outgrowth of the NOPR, we note that certain modifications in this order address, at least in part, concerns that Order No. 1920 diminished the role of states in contrast to the NOPR.[1687]

668. In the NOPR, the Commission proposed to require transmission providers to "seek the agreement"[1688] of Relevant State Entities based upon its finding that "providing state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning could help increase . . . state[] support for those facilities,"[1689] thereby framing such a

[1686] Utah Commission Rehearing Request at 11-12.

[1687] *See supra* Requirement Concerning Relevant State Entities' Preferred Cost Allocation Methods section; *infra* Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

[1688] NOPR, 179 FERC ¶ 61,028 at PP 278, 303, 305, 308.

[1689] *Id.* P 299.

formal opportunity for state regulators as the subject for commenter discussion.[1690] Although Order No. 1920 did not adopt the proposed requirement to "seek the agreement" of Relevant State Entities, the Commission adopted a materially similar requirement—the Engagement Period—for transmission providers to provide, over a six-month period, a forum for negotiation of cost allocation methods for Long-Term Regional Transmission Facilities that enables meaningful participation by Relevant State Entities.[1691] The Engagement Period "provide[s] state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning," precisely as contemplated in the NOPR.[1692] Indeed, as the Commission explained in Order No. 1920, "requiring an Engagement Period provides the same opportunity for robust engagement in the cost allocation process as the NOPR proposal, and thus has the potential to achieve the same important benefits, but will reduce the practical challenges associated with requiring transmission providers to seek the agreement of Relevant State Entities."[1693] The Engagement Period, which facilitates the meaningful involvement of Relevant State Entities in determining cost allocation methods for selected Long-Term Regional

[1690] *Conn. Light & Power Co. v. Nuclear Regul. Comm'n*, 673 F.2d at 533 (holding that an agency's proposed rule must "adequately frame the subjects for discussion").

[1691] Order No. 1920, 187 FERC ¶ 61,068 at PP 1354, 1357.

[1692] *See* NOPR, 179 FERC ¶ 61,028 at P 299.

[1693] Order No. 1920, 187 FERC ¶ 61,068 at P 1362.

Transmission Facilities, is in character with, and consequently a logical outgrowth of, the proposal to require transmission providers to "seek the agreement" of Relevant State Entities for the applicable cost allocation method for selected transmission facilities.[1694]

### 2. Requests Arguing the Engagement Period is Inferior to a Requirement that Transmission Providers Seek the Agreement of Relevant State Entities

#### a. Order No. 1920 Requirements

669. In Order No. 1920, the Commission established a six-month Engagement Period, during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.[1695]

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[1694] *See, e.g.*, *Am. Paper Inst. v. EPA*, 660 F.2d at 959 n.13 ("An agency may make even substantial changes in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given."); *accord Chocolate Mfrs. Ass'n of U.S. v. Block*, 755 F.2d 1098, 1105 (4th Cir. 1985).

[1695] Order No. 1920, 187 FERC ¶ 61,068 at P 1354.

**b. Requests for Rehearing and Clarification**

670. Virginia and North Carolina Commissions and West Virginia Commission request rehearing of Order No. 1920's decision to not adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[1696] West Virginia Commission argues that the Engagement Period is an ineffective substitute for the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[1697] Virginia and North Carolina Commissions argue that, to provide the robust engagement required by Order No. 1920, the Commission should specify and bolster transmission providers' requirements to meaningfully engage with and proactively seek (but not necessarily obtain) the agreement of Relevant State Entities concerning cost allocation issues during the Engagement Period.[1698]

[1696] West Virginia Commission Rehearing Request at 8; Virginia and North Carolina Commissions Rehearing Request at 8-10.

[1697] West Virginia Commission Rehearing Request at 8.

[1698] Virginia and North Carolina Commissions Rehearing Request at 9-10.

### c. Commission Determination

671. As discussed in Order No. 1920 and reiterated in this order, it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes. While we are unpersuaded by arguments that the Commission erred in declining to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities and instead establishing the Engagement Period,[1699] we believe that the requirements related to the Engagement Period, discussed below, that we adopt herein address the concerns underlying those rehearing requests.

672. In Order No. 1920, the Commission carefully weighed the appropriate level of transmission providers' engagement with Relevant State Entities regarding the cost allocation method to be applied to Long-Term Regional Transmission Facilities by considering the potential challenges inherent in such engagement. Specifically, the Commission found that while "states play a critical role in transmission planning" and "facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings," mandating

[1699] West Virginia Commission Rehearing Request at 8; Virginia and North Carolina Commissions Rehearing Request at 8-10.

that transmission providers seek the agreement of Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) would present potential difficulties that counseled against adoption of this proposed reform.[1700] For example, the Commission considered the possibility that requiring transmission providers to seek the agreement of Relevant State Entities might create disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans.[1701] The Commission also considered the challenges of adopting a definition for "agreement" that would be necessary under a requirement for transmission providers to seek the agreement of Relevant States Entities.[1702]

673. We continue to find, as stated above, that states "play a critical role in transmission planning" and "facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings,"[1703] and we find that establishing an Engagement Period recognizes that critical role while reducing the potential practical challenges discussed above, as

[1700] Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 1362.

[1701] *See id.* P 1362 & n.2906 (citing Minnesota State Entities NOPR Initial Comments).

[1702] *Id.* P 1361 (discussing commenter arguments that the Commission adopt different criteria for "agreement," including a majority, a threshold of one-half of the participating Relevant State Entities, or unanimity).

[1703] *Id.* PP 124, 1362.

compared to requiring transmission providers to seek the agreement of Relevant State Entities.[1704] We also continue to find that the Engagement Period provides the same opportunity for robust engagement in the cost allocation process as the NOPR proposal, and thus has the potential to achieve the same important benefits.[1705] Beyond that, the modification we make here, to require transmission providers to submit any cost allocation methods agreed to by Relevant State Entities in the transmittal or as an attachment to their compliance filings, addresses the same concern and provides Relevant State Entities with additional means to demonstrate to the Commission any preferences around the cost allocation of Long-Term Regional Transmission Facilities. We therefore are unpersuaded by arguments raised by West Virginia Commission on rehearing that the Engagement Period is "ineffective" compared to the NOPR proposal.[1706] Similarly, with respect to Virginia and North Carolina Commissions' request that the Commission require transmission providers to "proactively seek" the agreement of Relevant State Entities to the transmission providers' preferred Long-Term Regional Transmission Cost Allocation Method,[1707] we find that Order No. 1920, as modified on rehearing, provides more opportunities for state engagement than a requirement to simply seek agreement with states for a Long-Term Regional Transmission Cost Allocation Method.

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[1704] *Id.* P 1362.

[1705] *Id.*

[1706] West Virginia Commission Rehearing Request at 8.

[1707] Virginia and North Carolina Commissions Rehearing Request at 10.

Specifically, transmission providers must (1) provide the opportunity for Relevant State Entities from all states in a transmission planning region to participate in the Engagement Period;[1708] (2) upon the request of Relevant State Entities, facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities;[1709] and (3) include, in the transmittal or as an attachment to their compliance filings, any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process agreed to by Relevant State Entities.[1710]

### 3. Duration of the Engagement Period

#### a. Order No. 1920 Requirements

674. In Order No. 1920, the Commission found that limiting the Engagement Period to six months was necessary to ensure that transmission providers have sufficient time to prepare their compliance filings in advance of the compliance deadlines established in Order No. 1920.[1711]

#### b. Requests for Rehearing and Clarification

675. Several rehearing parties request extension of the Engagement Period.[1712] PJM States and Pennsylvania Commission request that the Commission clarify that the six-

[1708] *See infra* Content of the Engagement Period section.

[1709] *See supra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1710] *See supra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1711] Order No. 1920, 187 FERC ¶ 61,068 at P 1358.

[1712] PJM States Rehearing Request at 3-4; Pennsylvania Commission Rehearing

month Engagement Period will be extended for up to 12 months if states file a unanimous declaration that they are engaged in, but require additional time to complete, cost allocation discussions.[1713] West Virginia Commission requests that the Commission extend the Engagement Period to a minimum of 12 months or, in the alternative, authorize the extension of the Engagement Period if Relevant State Entities submit a declaration stating that they are continuing to engage in cost allocation discussions.[1714] SERTP Sponsors request that the Commission clarify that, upon unanimous consent of all affected state commissions (and the governing authorities for non-jurisdictional transmission providers), the Commission will allow (or, at a minimum, consider good-cause motions for) an extension of time for the development of *ex ante* state agreements to provide those entities with additional time to negotiate during the Engagement Period.[1715] PJM States, Pennsylvania Commission, and West Virginia Commission argue that the Commission should permit an extension of the Engagement Period because there are a large number of Relevant State Entities in PJM, there are highly diverse regulatory models used in those Relevant State Entities in PJM, and there are a wide variety of state

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Request at 1 (adopting PJM States' arguments); West Virginia Commission Rehearing Request at 13; SERTP Sponsors Rehearing Request at 7-8; Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

[1713] PJM States Rehearing Request at 3-4; Pennsylvania Commission Rehearing Request at 1.

[1714] West Virginia Commission Rehearing Request at 13.

[1715] SERTP Sponsors Rehearing Request at 7-8.

laws and procedures applicable to those Relevant State Entities.[1716] Virginia and North Carolina Commissions argue that it would likely be beneficial to afford transmission providers greater flexibility with respect to the "timeline" of the Engagement Period, to the extent this flexibility would facilitate productive engagement with states without unduly delaying or impeding Order No. 1920's other requirements.[1717]

676. Wyoming Commission asserts that providing states with six months "to reach agreement with the default cost allocation looming is an illusory acknowledgement of state authority."[1718] Arizona Commission states that "the provision for states to negotiate acceptable cost allocations among them is limited to six months" and that "[s]ix months is not enough time for the states to establish rate cases."[1719] Designated Retail Regulators and Undersigned States argue that "reaching an agreement in MISO within the six-month window" may be difficult given states' different goals and agendas,[1720] and that six months is an insufficient amount of time to provide the due process required to approve any State Agreement Process.[1721]

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[1716] PJM States Rehearing Request at 3; Pennsylvania Commission Rehearing Request at 1; West Virginia Commission Rehearing Request at 13.

[1717] Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

[1718] Wyoming Commission Rehearing Request at 7.

[1719] Arizona Commission Rehearing Request at 17 n.14.

[1720] Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31.

[1721] Designated Retail Regulators Rehearing Request at 9; Undersigned States Rehearing Request at 9.

### c. Commission Determination

677. We set aside, in part, Order No. 1920's requirements on the duration of the Engagement Period. In Order No. 1920, the Commission noted that experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states.[1722] Moreover, the Commission found that facilitating state involvement in the regional cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[1723] In keeping with these findings, and upon further consideration, we find that extending the Engagement Period may be appropriate when Relevant State Entities represent to the Commission that they need additional time to complete cost allocation discussions.

678. Providing the opportunity for such an extension is consistent with the critical role that states play in addressing these issues and ensuring that they have the time necessary to adequately engage in these issues. Therefore, in response to arguments raised by PJM States, Pennsylvania Commission, and West Virginia Commission, we set aside Order No. 1920's requirements, in part, to specify that the Commission will grant an extension of the required Engagement Period for up to an additional six months when Relevant State Entities, consistent with their chosen method to reach agreement, request additional

[1722] Order No. 1920, 187 FERC ¶ 61,068 at P 124.

[1723] *Id.*

time to complete cost allocation discussions. We find that such an extension is warranted in that circumstance to ensure that Relevant State Entities have sufficient time to engage in fulsome discussions. We also clarify that in such circumstances, the Commission will also, as appropriate, extend, *sua sponte*, the relevant Order No. 1920 compliance deadlines to accommodate an extension of the Engagement Period and to ensure that any such extension would not conflict with the required compliance deadlines.

#### 4. Content of the Engagement Period

##### a. Order No. 1920 Requirements

679. In Order No. 1920, the Commission required the transmission providers in each transmission planning region to provide notice, such as on their OASIS pages or public websites, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period. The Commission required that such notice include contact information for a single point of contact in the transmission planning region that the Relevant State Entities can use to communicate any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement, which must be no earlier than the end date of the Engagement Period.[1724] The Commission also required transmission providers in each transmission planning

[1724] *Id.* P 1356. The Commission noted Relevant State Entities must indicate that they have agreed to any State Agreement Process for any such process to be eligible for acceptance by the Commission in compliance with Order No. 1920. *Id.* P 1356 n.2895.

region to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period.[1725]

680. The Commission required that transmission providers explain on compliance how they complied with the requirement to establish and provide notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as how they complied with the requirement to provide a forum for such negotiation.[1726]

681. The Commission declined to define what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement during the Engagement Period, or to establish a minimum set of criteria for a state agreement. Instead, the Commission left such matters, including whether to use existing state processes as a forum for negotiations, to the Relevant State Entities participating in the Engagement Period to determine.[1727] The Commission also declined to expand participation in the Engagement Period beyond Relevant State Entities, stating that it did not find it necessary to allow other stakeholders to participate in the Engagement Period.[1728]

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[1725] *Id.* P 1357.

[1726] *Id.*

[1727] *Id.* PP 1360-1361 (citations omitted).

[1728] *Id.* P 1363.

### b. Requests for Rehearing and Clarification

682. PJM States and NARUC request that the Commission require transmission providers to include in their compliance filings, at minimum, the setting and communicating of deadlines and the general forum for transmission provider discussions with and outreach to state entities concerning the Engagement Period.[1729] PJM States contend that these and other clarifications would demonstrate the extent to which transmission providers engaged with states during the Engagement Period.[1730]

683. PJM States request clarification that the Engagement Period is actually a "State Engagement Period" and that "states are *the* stakeholder(s) to engage."[1731] PJM States explain that any such clarification should not prohibit states from inviting other entities that might be helpful in assisting states in reaching agreement on cost allocation. Rather, PJM States argue that the Commission should make clear that the Engagement Period is "not for the engagement of all stakeholders" but is instead intended to provide a forum for transmission providers and states to attempt to reach agreement on cost allocation.[1732]

### c. Commission Determination

684. In response to the requests of PJM States and NARUC for clarification as to the information that transmission providers must include in their compliance filings

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[1729] NARUC Rehearing Request at 17; PJM States Rehearing Request at 7.

[1730] PJM States Rehearing Request at 8.

[1731] *Id.* (emphasis in original).

[1732] *Id.* at 8-9.

concerning the Engagement Period,[1733] we clarify that, in order to comply with the requirement that transmission providers explain how they provided a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process during the Engagement Period that enables meaningful participation by Relevant State Entities,[1734] transmission providers must at minimum disclose any deadlines set by transmission providers during the Engagement Period and how transmission providers communicated any such deadlines to Relevant State Entities, and provide a general description of the forum for negotiation.[1735]

685. With respect to PJM States' argument that the Commission should clarify that the Engagement Period is "not for the engagement of all stakeholders,"[1736] we reiterate that the Commission declined to expand participation in the Engagement Period beyond Relevant State Entities, and did not find it necessary to allow other stakeholders to participate in the Engagement Period.[1737] However, we also reiterate that the

[1733] *See id.* at 7; NARUC Rehearing Request at 17-18.

[1734] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1735] We address the requests of PJM States, NARUC, and other parties that the Commission require transmission providers to include additional information related to the Engagement Period in their compliance filings—such as requests that the Commission require each transmission provider to include states' preferred cost allocation method in its compliance filing above in the Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1736] PJM States Rehearing Request at 8-9.

[1737] Order No. 1920, 187 FERC ¶ 61,068 at P 1363.

Commission allowed Relevant State Entities to permit the participation of other entities subsequently during implementations of a State Agreement Process.[1738] We also reiterate our determination in Order No. 1920 to define Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state,[1739] and we continue to find that this definition recognizes the important role of states while providing sufficient regional flexibility for effective Engagement Period participation.[1740]

686. With respect to PJM States' request for clarification that the Engagement Period is actually a "State Engagement Period" and that the states are the stakeholders with which transmission providers must engage during the Engagement Period,[1741] we grant clarification, in part, and clarify that transmission providers must provide the opportunity for Relevant State Entities from all states in each transmission planning region to participate in the Engagement Period.

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[1738] *Id.* P 1402.

[1739] *Id.* P 1355.

[1740] *Id.* P 1364.

[1741] PJM States Rehearing Request at 8.

### 5. Consultation with Relevant State Entities After the Engagement Period

#### a. Order No. 1920 Requirements

687. In Order No. 1920, the Commission declined to require future Engagement Periods, but noted that transmission providers may hold future Engagement Periods if they believe that such periods would be beneficial.[1742]

#### b. Requests for Rehearing and Clarification

688. NARUC and NESCOE request rehearing of Order No. 1920's decision not to require future Engagement Periods.[1743] NESCOE argues that following the initial Engagement Period, any proposed modification to the transmission planning region's Long-Term Regional Transmission Cost Allocation Method should trigger an obligation to establish a new Engagement Period to provide a forum for Relevant State Entities to discuss the proposed Long-Term Regional Transmission Cost Allocation Method. NESCOE explains that absent this obligation, a transmission provider could undo the efforts of Relevant State Entities in agreeing to a Long-Term Regional Transmission Cost Allocation Method during the initial Engagement Period by filing a new Long-Term Regional Transmission Cost Allocation Method without consulting with Relevant State Entities.[1744]

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[1742] Order No. 1920, 187 FERC ¶ 61,068 at P 1368.

[1743] NARUC Rehearing Request at 21-22; NESCOE Rehearing Request at 13-14.

[1744] NESCOE Rehearing Request at 13-14 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1430 ("We further clarify that unless voluntarily waived, a transmission provider retains its FPA section 205 filing rights to submit an *ex ante* cost allocation

689. NARUC requests that the Commission create a mechanism that ensures regular re-examination of the Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process in a transmission provider's OATT. Specifically, NARUC argues that the Commission should require each transmission provider to periodically open a new negotiation period with Relevant State Entities.[1745]

690. Virginia and North Carolina Commissions argue that it would likely be beneficial to afford transmission providers greater flexibility with respect to the "frequency" of the Engagement Period, to the extent this flexibility would facilitate productive engagement with states without unduly delaying or impeding Order No. 1920's other requirements.[1746]

### c. Commission Determination

691. We are persuaded by NARUC's and NESCOE's arguments raised on rehearing. Accordingly, we set aside Order No. 1920, in part, and require that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State

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method for Long-Term Regional Transmission Facilities at any time, consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO." (citations omitted))).

[1745] NARUC Rehearing Request at 21-22. In the Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section above, we discuss NARUC's alternative request that the Commission require each transmission provider to file a modification to its OATT if states reach the requisite agreement on a different cost allocation method than that reflected in its OATT.

[1746] Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process. The consultation requirement will provide a mechanism through which transmission providers and Relevant State Entities can engage regarding possible future changes via FPA section 205 to cost allocation methods accepted by the Commission in compliance with Order No. 1920.[1747] We require transmission providers to include in their OATTs a description of how they will consult with Relevant State Entities in these circumstances. Additionally, for a consultation initiated by the transmission providers, we require transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment. For a consultation initiated by Relevant State Entities, if the transmission providers choose not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) preferred by Relevant State Entities during the required consultation, we also require transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.

[1747] We clarify that this consultation requirement neither requires transmission providers to submit, nor prohibits transmission providers from submitting, FPA section 205 filings to modify cost allocation methods accepted in compliance with Order No. 1920, and transmission providers therefore retain their currently effective FPA section 205 rights. That said, as noted below, transmission providers may satisfy the consultation requirement by voluntarily agreeing to submit FPA section 205 proposals supported by Relevant State Entities. *Infra* P 692.

692. We find that these requirements will ensure that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920, which has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities.[1748] While we provide transmission providers flexibility as to the form and duration of their required consultation with Relevant State Entities, we note that one way transmission providers could satisfy the requirement to consult with Relevant State Entities is by revising their OATTs to include a process under which the transmission provider must present to the Commission, in addition to its own FPA section 205 proposal, an alternative cost allocation method proposed by Relevant State Entities for evaluation by the Commission on equal footing.[1749] Transmission providers could

[1748] *E.g.*, Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126.

[1749] *See, e.g.*, ISO New England Inc., FERC FPA Electric Tariff, ISO New England Inc. Agreements and Contracts, TOA, Transmission Operating Agreement (5.0.0), 3.04(h)(vi)(C); *see also The Governors of Conn., Me., Mass., N.H., R.I., Vt.*, 112 FERC ¶ 61,049, at P 25 (2005).

also satisfy the requirement to consult with Relevant State Entities by revising their OATTs to include mechanisms similar to those used in SPP[1750] and MISO.[1751]

### D. Design and Operation of State Agreement Processes

#### 1. Definition of Relevant State Entities

##### a. Order No. 1920 Requirements

693. In Order No. 1920, the Commission defined Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state. The Commission stated that it modified the NOPR proposal's definition to add the word "electric" before "utility regulation" in order to make clear that Relevant State Entities are those state agencies responsible for *electric* utility regulation, and not other types of

[1750] SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), 7.2 (Regional State Committee) (providing that the Regional State Committee has primary responsibility for determining regional proposals regarding, among other things, "whether license plate or postage stamp rates will be used for the regional access charge," and that when the Regional State Committee "reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the [FPA]"); *see also Sw. Power Pool, Inc.*, 106 FERC ¶ 61,110, at PP 218-220, *order on reh'g*, 109 FERC ¶ 61,010, at PP 92-94 (2004); *Sw. Power Pool, Inc.*, 108 FERC ¶ 61,003, at P 127 & n.90 (2004), *order on reh'g*, 110 FERC ¶ 61,138, at P 33 (2005).

[1751] MISO FERC Electric Tariff, MISO Rate Schedules, MISO Transmission Owner Agreement, app. K (Filing Rights Pursuant To Section 205 Of The FPA) (3.0.0), II.E.3.a.i-ii (providing the circumstances under which the OMS Committee "shall have the right to request and MISO shall file for a new or an amendment of any regional cost allocation methodology"); *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,165, at PP 30, 32 (2013).

utility regulation.[1752] In Order No. 1920, the Commission declined requests to expand or clarify the definition of Relevant State Entities and did not modify the definition beyond adding the word "electric," but permitted other participants beyond Relevant State Entities to participate in a State Agreement Process, if agreed to by Relevant State Entities.[1753]

**b. Requests for Rehearing and Clarification**

694. APPA contends that the Commission erred in excluding municipal electric regulatory bodies from the Relevant State Entity definition.[1754] APPA claims that excluding public power utilities and municipal governing bodies is arbitrary and capricious because: (1) the Commission failed to justify excluding customers served by municipal utilities during the Engagement Period, which is unduly discriminatory;[1755] (2) the Commission gave no meaningful rationale for excluding self-regulated public utilities from the Relevant State Entity definition, and inclusion would increase local support and reduce uncertainty and risk for development of Long-Term Regional Transmission Facilities; and (3) the definition of Relevant State Entity conflicts with the FPA's definition of "state commission" as "the regulatory body of the State or

[1752] Order No. 1920, 187 FERC ¶ 61,068 at P 1355.

[1753] *Id.* PP 1364 & n.2914, 1402.

[1754] APPA Rehearing Request at 2.

[1755] *Id.* at 4.

*municipality* having jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State or *municipality*."[1756]

695. Large Public Power claims that non-jurisdictional self-regulating non-public utilities under FPA section 201(f) could be profoundly affected by the Engagement Period without representation, and their exclusion from the definition of Relevant State Entity is arbitrary and capricious.[1757] Large Public Power states that its members are self-regulating entities that possess many of the same regulatory characteristics as state commissions, undertake retail ratemaking publicly, are not represented by state commissions, and in some states represent a market share larger than most individual investor-owned utilities.[1758] Large Public Power states that the FPA explicitly recognizes political subdivisions' authority through exemptions.[1759] Large Public Power argues that the Commission should provide an opportunity for municipal utilities to have a voice equal to that of state utility commissions to ensure that Long-Term Regional Transmission Facilities are not built and paid for by their customers unless such facilities are needed and wanted.[1760] Large Public Power states that the most obvious solution to

[1756] *Id.* at 5 (citing 16 U.S.C. 796(15)) (emphasis in original).

[1757] Large Public Power Rehearing Request at 11.

[1758] *Id.*

[1759] *Id.* at 12.

[1760] *Id.* at 12-13.

this issue would be to grant municipal utilities representation on a load ratio share basis.[1761]

696. City of New Orleans Council requests clarification to confirm that it meets the definition of a Relevant State Entity.[1762] City of New Orleans Council states that it is designated and recognized by the State of Louisiana and the Home Rule Charter of the City of New Orleans as the governmental body that supervises, regulates, and controls public utilities within New Orleans.[1763] City of New Orleans Council states that MISO recognizes the City of New Orleans Council's unique regulatory authority and status.[1764] Noting that Order No. 1920 refers to OMS as an existing mechanism for state involvement, City of New Orleans Council states that it is a member of OMS that represents the collective interests of its members, which are state and local regulators within MISO's footprint.[1765] City of New Orleans Council states that it is also a member of the Entergy Regional State Committee (ERSC), which is comprised of retail regulators from the MISO-South subregion and recognized in MISO stakeholder forums, and that the ERSC bylaws recognize that the City of New Orleans Council is included as a "state

[1761] *Id.* at 13.

[1762] City of New Orleans Council Rehearing Request at 4.

[1763] *Id.* (citing La. Const., art. IV, § 21(c); Home Rule Charter of the City of New Orleans, § 3-130).

[1764] *Id.* at 5.

[1765] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1357).

regulatory agency."[1766] City of New Orleans Council also argues that its recognition within MISO is consistent with PJM's recognition of the District of Columbia.[1767]

697. City of New Orleans Council requests rehearing in the event that the Commission does not grant its request for clarification, noting that the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans recognize City of New Orleans Council's status as the governmental body with the power of supervision, regulation, and control over public utilities, and noting MISO's recognition of the City of New Orleans Council's status.[1768] City of New Orleans Council states that finding that it does not meet the definition of Relevant State Entity would be contrary to such legal and regulatory recognition.[1769]

698. NESCOE requests that the Commission clarify that Regional State Committees are included in the definition of Relevant State Entities, or in the alternative, NESCOE seeks rehearing.[1770] NESCOE states that it is unclear that Regional State Committees, such as NESCOE, which do not necessarily appear in state laws and are not necessarily state

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[1766] *Id.* at 6 (citing Entergy Regional State Committee (ERSC), https://www.misoenergy.org/engage/committees/entergy-regional-state-committee/ (ERSC Mission Statement); ERSC Bylaws, https://cdn.misoenergy.org/ERSC%20Bylaws%20(Amended%202%2014%2022)%2017600.pdf (amended Feb. 14, 2022)).

[1767] *Id.* at 6-7.

[1768] *Id.* at 8.

[1769] *Id.* at 9.

[1770] NESCOE Rehearing Request at 17-20.

agencies, are Relevant State Entities.[1771] NESCOE states that it appears that the Commission did not deliberately exclude Regional State Committees from the definition of Relevant State Entities, but that the Commission appears to have misapprehended NESCOE's argument in its comments as solely concerned about its unique structure of achieving consensus among the New England states.[1772]

699. NRECA states that, even following its comments to the NOPR, the definition of Relevant State Entity excludes cooperatives and public power utilities not subject to regulation by a state utility commission and the Engagement Period includes only Relevant State Entities. NRECA argues that, as a result, Order No. 1920 allows a Relevant State Entity to dictate cost allocation to electric utilities it does not regulate.[1773]

### c. Commission Determination

700. We deny the requests for clarification and disagree with APPA's and Large Public Power's requests for rehearing asking to expand the definition of Relevant State Entity.[1774] As discussed in Order No. 1920, we continue to find that "regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders – in particular, a state regulator responsible for permitting

[1771] *Id.* at 18-19.

[1772] *Id.* at 19.

[1773] NRECA Rehearing Request at 57-58.

[1774] APPA Rehearing Request at 2, 4-5; Large Public Power Rehearing Request at 11-13.

transmission facilities – do not perceive the regional transmission facilities' value as commensurate with their costs."[1775]

701. Municipal electric regulatory bodies and non-public utility entities provide valuable insight as stakeholders in Commission-sanctioned processes. But in defining Relevant State Entities for the purposes of Order No. 1920, we find that state entities responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region are, as discussed above, uniquely situated to influence whether or not a Long-Term Regional Transmission Facility reaches completion. On balance, while we recognize the important role that other stakeholders play in Long-Term Regional Transmission Planning, we continue to find that the definition of Relevant State Entities should encompass only any state entities responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.[1776] In Order No. 1920, the Commission further stated, and we continue to believe, that:

> [P]roviding state regulators with a formal opportunity to develop a cost allocation method for Long-Term Regional Transmission Facilities selected through Long-Term Regional Transmission Planning could help increase stakeholder – and

[1775] Order No. 1920, 187 FERC ¶ 61,068 at P 1364 (quoting NOPR, 179 FERC ¶ 61,028 at P 297 (footnote omitted)).

[1776] As noted below, we make no findings here regarding whether any individual municipal electric regulatory body or non-public utility entity meets the definition of a Relevant State Entity, as those determinations properly rest with entities in a state, based upon their interpretation of their state laws. *Infra* P 703.

> state – support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable Commission-jurisdictional rates.[1777]

702. For the same reasons, we also do not find it necessary to expand the definition of Relevant State Entities for the purposes of Order No. 1920.

703. In response to City of New Orleans Council's and NESCOE's requests,[1778] we will not make a finding on whether an individual state's laws, regulations, and/or policies, or inclusion in a larger association of regulators, deem a certain entity to be a Relevant State Entity, though we note that state law may be a persuasive or dispositive factor in such determinations.[1779] Instead, entities within a state must determine if they qualify as Relevant State Entities based on the definition the Commission provided in Order No. 1920 and based upon their interpretation of their state laws. We also reiterate that Order No. 1920 permits other participants, including municipal electric regulatory bodies and non-public utility entities that do not otherwise meet the definition of a Relevant State Entity, to participate in a State Agreement Process, if agreed to by

[1777] Order No. 1920, 187 FERC ¶ 61,068 at P 1364 (alterations omitted) (citing NOPR, 179 FERC ¶ 61,028 at P 299).

[1778] City of New Orleans Council Rehearing Request at 4, 8; NESCOE Rehearing Request at 17-20.

[1779] Order No. 1920 also allows Relevant State Entities to participate in cost allocation negotiations through a regional body. *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 999 (declining to impose specific requirements regarding how consultation with Relevant State Entities will occur, and recognizing need for flexibility "based on the specific needs and makeup of their transmission planning region").

Relevant State Entities.[1780] Finally, we disagree with NRECA's assertion that Order No. 1920 permits Relevant State Entities to dictate cost allocation to utilities they do not regulate.[1781] Order No. 1920, as modified here on rehearing, provides robust opportunities for Relevant State Entities to participate in the development of Long-Term Regional Transmission Cost Allocation Methods, given the critical role that states will play in the success of Long-Term Regional Transmission Planning. However, it is ultimately the Commission that will determine whether cost allocation methods proposed on compliance are just and reasonable and not unduly discriminatory or preferential, and all interested parties will have a full and fair opportunity to participate both in regional stakeholder proceedings and in compliance proceedings before the Commission.

704. In response to APPA's contention that the definition of Relevant State Entity conflicts with the FPA's definition of "state commission" as "the regulatory body of the State or *municipality* having jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State or *municipality*,"[1782] we find that the definition of Relevant State Entity for purposes of Long-Term Regional Transmission Facility cost allocation is distinct from the purpose of the definition of "state commission" in the FPA and need not align with it. We note, for example, that the FPA

[1780] *Id.* PP 1364 & n.2914, 1402.

[1781] NRECA Rehearing Request at 57-58.

[1782] APPA Rehearing Request at 5 (citing 16 U.S.C. 796(15)) (emphasis in original).

defines "state commission" and "state" separately, and in the final rule we use neither of these two definitions.[1783]

### 2. Extensions of Time for Negotiation of Cost Allocation Methods Under State Agreement Processes

#### a. Order No. 1920 Requirements

705. In Order No. 1920, the Commission required that any State Agreement Process be completed, i.e., any resulting cost allocation method must be filed with the Commission, no later than six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities).[1784] The Commission found that the State Agreement Process can only be effective if there is a limit on the time to reach agreement before defaulting to the Long-Term Regional Transmission Cost Allocation Method that the Commission required transmission providers to include in their OATTs, that the lack of such a deadline could cause delay and increase uncertainty regarding selected Long-Term Regional Transmission Facilities, and that a deadline, bolstered by a default Long-Term Regional Transmission Cost Allocation Method, may increase the incentive for Relevant State Entities to reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.[1785] The Commission found that six months is a reasonable period for State Agreement Process

[1783] *See* 16 U.S.C. 796(15)) and 16 U.S.C. 796(6), respectively.

[1784] Order No. 1920, 187 FERC ¶ 61,068 at P 1406.

[1785] *Id.* P 1413.

deliberations on a cost allocation method because it balances the need for adequate time for negotiations with transmission providers' need for finality in their Long-Term Regional Transmission Planning.[1786]

### b. Requests for Rehearing and Clarification

706. Designated Retail Regulators and Undersigned States argue that the State Agreement Process is unreasonable because Order No. 1920 does not provide adequate time for the adoption of a cost allocation method that follows any approved State Agreement Process.[1787]

707. SERTP Sponsors request that the Commission clarify that upon unanimous consent of state commissions and relevant governing authorities for SERTP Sponsors not subject to the Commission's jurisdiction, the Commission will allow an extension of time for the development of methods resulting from a State Agreement Process.[1788] SERTP Sponsors request that at a minimum, the Commission clarify that it will consider motions for an extension of time for good cause.[1789]

### c. Commission Determination

708. We believe that the six-month deadline by which transmission providers must file any cost allocation method that results from a State Agreement Process is reasonable and

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[1786] *Id.* P 1414.

[1787] Designated Retail Regulators Rehearing Request at 9; Undersigned States Rehearing Request at 8.

[1788] SERTP Sponsors Rehearing Request at 7-8.

[1789] *Id.*

are thus unpersuaded by parties who challenge the sufficiency of this deadline. While we emphasize the benefits of a State Agreement Process, we continue to find that this deadline balances the need for adequate time for Relevant State Entities to conduct negotiations with the need for finality in Long-Term Regional Transmission Planning.[1790] Consistent with Order No. 1920, we find that a deadline, coupled with a default Long-Term Regional Transmission Cost Allocation Method, may encourage Relevant State Entities to timely reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.[1791] While we grant SERTP Sponsors' request to clarify that transmission providers may file motions for an extension of time for good cause to the State Agreement Process beyond six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities), we decline at this time to categorically pre-approve extensions (even if unanimous), and thus we deny SERTP Sponsors' associated request for clarification. Instead, the Commission will consider any such requests on the record before it at that time.

[1790] Order No. 1920, 187 FERC ¶ 61,068 at P 1414.

[1791] *Id.* P 1413.

### E. Use of Existing Cost Allocation Methods in Long-Term Regional Transmission Planning or Existing Regional Processes

#### 1. Order No. 1920 Requirements

709. In Order No. 1920, the Commission required that, to the extent transmission providers believe that their existing cost allocation methods comply with the requirements of Order No. 1920, they may demonstrate in their compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of Order No. 1920.[1792] The Commission also required that transmission providers that wish to continue using existing transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning.[1793]

#### 2. Requests for Rehearing and Clarification

710. PJM requests that the Commission grant rehearing and confirm that it will consider requests to maintain existing cost allocation methods on compliance unless and until an alternative is filed.[1794] PJM argues that the Commission has not justified why Order No. 1920 "categorically prohibit[s] existing cost allocation methodologies from remaining in place" in such circumstances.[1795] PJM states that it is concerned that

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[1792] *Id.* PP 1302-1303.

[1793] *Id.* P 243.

[1794] PJM Rehearing Request at 19-23.

[1795] *Id.* at 20.

requiring transmission owners to re-justify existing cost allocation methods will set back efforts to implement its Long-Term Regional Transmission Planning Process.[1796] PJM argues that the requirement to renegotiate all cost allocation methods undercuts the longstanding and widely-accepted notion that knowing how costs for transmission facilities will be allocated is critical for their development.[1797] PJM further states that its existing cost allocation method includes specific cost allocations for reliability-based projects, market efficiency projects, public policy projects addressing state-identified needs, and multi-driver projects.[1798] PJM argues that requiring transmission owners to re-justify the existing cost allocation methods undermines the certainty regarding the development of transmission facilities PJM selects to be built.[1799] PJM states that its existing cost allocation methods are the result of years of close consultation and extensive work among the states in the PJM region and litigation before the Commission. PJM argues that Order No. 1920 effectively erases these efforts.[1800]

711. Ohio Commission Federal Advocate asserts that Order No. 1920 arbitrarily and capriciously requires continued use of PJM's State Agreement Approach to be re-approved by the Commission. Specifically, Ohio Commission Federal Advocate argues

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[1796] *Id.* at 20-21.

[1797] *Id.* at 21 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 124).

[1798] *Id.* at 22-23.

[1799] *Id.* at 21.

[1800] *Id.* at 22-23.

that the State Agreement Approach has long been approved and used in the PJM region to ensure just and reasonable cost allocation for public policy projects and asks the Commission to revise Order No. 1920 to explicitly allow the continued use of the State Agreement Approach at least to the projects to which it currently applies.[1801]

### 3. Commission Determination

712. Upon consideration of the rehearing requests, we sustain Order No. 1920's requirement that transmission providers that wish to continue using existing transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning. We similarly decline to set aside Order No. 1920's requirement that to use an existing cost allocation method as a Long-Term Regional Transmission Cost Allocation Method, a transmission provider must demonstrate in its compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, comply with Order No. 1920.

713. We disagree with PJM's request to continue to use existing regional cost allocation methods for Long-Term Regional Transmission Facilities without a showing that such use complies with the requirements of Order No. 1920.[1802] However, we note that Order No. 1920 does not prohibit transmission providers from proposing to use existing regional cost allocation methods to comply with the requirements for Long-Term

[1801] Ohio Commission Federal Advocate Rehearing Request at 12-13.

[1802] PJM Rehearing Request at 19-23.

Regional Transmission Cost Allocation Methods, so long as the transmission providers demonstrate that the existing methods are just and reasonable and not unduly discriminatory or preferential when applied to Long-Term Regional Transmission Facilities and comply with the requirements of Order No. 1920 and the cost causation principle.[1803] Nevertheless, given the deficiencies identified in existing transmission planning and cost allocation processes identified by the Commission in Order No. 1920 and the numerous reforms adopted in Order No. 1920 for Long-Term Regional Transmission Planning to address those deficiencies, it would be unjust and unreasonable for the Commission to accept existing cost allocation methods for Long-Term Regional Transmission Facilities without ensuring that such methods are consistent with Order No. 1920.[1804]

714. We recognize that it may be just and reasonable to apply existing regional cost allocation methods to Long-Term Regional Transmission Facilities for many of the same reasons that the Commission found these methods to be just and reasonable when initially approving them. For this reason, Order No. 1920 specifically provided that transmission providers may demonstrate in their compliance filings that their existing regional cost allocation methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of Order No. 1920.[1805] As such, we disagree with PJM's

[1803] Order No. 1920, 187 FERC ¶ 61,068 at PP 1302-1303.

[1804] *Id.* PP 124-125 (citations omitted), 1302-1303 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 565; Order No. 1000-A, 139 FERC ¶ 61,132 at P 747).

[1805] *Id.* PP 1302-1303. In Order No. 1000, in response to "concerns regarding

assertion that Order No. 1920 will ignore past efforts to facilitate consensus on cost allocation methods.[1806]

715. We disagree with Ohio Commission Federal Advocate's assertion that Order No. 1920 requires that the continued use of PJM's State Agreement Approach must be re-approved by the Commission and that the final rule limits use of PJM's State Agreement Approach.[1807] We note that Order No. 1920 requires reapproval for existing cost allocation methods' use in Long-Term Regional Transmission Planning only if those

relitigation of existing Commission-approved transmission cost allocation methods," the Commission declined "to prejudge whether any such existing cost allocation methods compl[ied] with the requirements of [Order No. 1000]," and noted that "[t]o the extent [transmission providers] believe[d] that to be the case with their region, they [could] take such positions during the development of compliance proposals and during Commission review of compliance filings." Order No. 1000, 136 FERC ¶ 61,051 at P 565. On compliance, the Commission found that SPP's existing Balanced Portfolio and Highway/Byway regional cost allocation methods and MISO's existing regional cost allocation methods for Multi-Value Projects (MVPs) and Market Efficiency Projects (MEP) complied with the requirements of Order No. 1000. *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,059, at PP 336, 347 (2013), *order on reh'g and compliance*, 149 FERC ¶ 61,048, at P 276 (2014), *order on reh'g and compliance*, 151 FERC ¶ 61,045, *order on compliance*, 152 FERC ¶ 61,106 (2015); *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, at PP 420, 434 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,127, at P 404 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,037 (2015), *order on compliance*, Docket No. ER13-187-010 (Mar. 31, 2015) (delegated order).

[1806] PJM Rehearing Request at 22-23. With respect to PJM's request to continue using its existing regional cost allocation method for public policy projects addressing state-identified needs outside of Long-Term Regional Transmission Planning, we address this issue above in the Requirement to Participate in Long-Term Regional Transmission Planning section.

[1807] Ohio Commission Federal Advocate Rehearing Request at 12-13.

methods are to be used for compliance with Order No. 1920.[1808] PJM's State Agreement Approach is not a regional cost allocation method used to comply with the requirements of Order No. 1000. The Commission approved the existing PJM State Agreement Approach in an order on compliance in the Order No. 1000 proceeding, but did not find that the PJM State Agreement Approach was a regional cost allocation method compliant with the requirements of Order No. 1000.[1809] In addition, PJM's State Agreement Approach is different than the "State Agreement Process" as discussed in Order No. 1920. The State Agreement Process referenced in Order No. 1920 is a new construct under which Relevant State Entities may agree to a different cost allocation method for Long-Term Regional Transmission Facilities than the generally applicable Long-Term Regional Transmission Cost Allocation Method on file. Therefore, we clarify that Order No. 1920 does not prohibit PJM from maintaining its existing State Agreement Approach for transmission facilities that are not selected in either its Order No. 1000 regional transmission planning process or through Long-Term Regional Transmission

[1808] Order No. 1920, 187 FERC ¶ 61,068 at PP 1302-1303.

[1809] *See PJM Interconnection, L.L.C.* 142 FERC ¶ 61,214, at P 142 (2013) ("We find PJM's proposed State Agreement Approach is not needed for PJM to comply with the provisions of Order No. 1000 addressing transmission needs driven by public policy requirements. PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 addressed above. Accordingly, the Commission need not find that the State Agreement Approach and corresponding cost allocation method comply with Order No. 1000."), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038, *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

Planning.[1810] To clarify further, PJM's State Agreement Approach is supplemental to PJM's existing regional transmission cost allocation method and, as a result, is not in any way affected by Order No. 1920.

716. However, if the Relevant State Entities in PJM agree to rely on its existing PJM State Agreement Approach as an Order No. 1920 State Agreement Process that applies to selected Long-Term Regional Transmission Facilities, and if PJM agrees, PJM would have to propose and demonstrate on compliance that its State Agreement Approach complies with all of the State Agreement Process requirements set forth in Order No. 1920. In addition, we reiterate that the *ex ante* Long-Term Regional Transmission Cost Allocation Method(s) that Order No. 1920 prescribes would be used to allocate the costs of selected Long-Term Regional Transmission Facilities if any Order No. 1920-compliant State Agreement Process does not result in a cost allocation method within six months after a project is selected, as described in the final rule. As noted above, the Commission will consider the entire record – including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal – when setting the replacement rate.

[1810] *See supra* Requirement to Participate in Long-Term Regional Transmission Planning section (responding to Pennsylvania Commission's and PJM States' requests regarding the PJM State Agreement Approach).

717. In addition, more generally, we clarify that we permit continued use of other existing state agreement approaches and similar voluntary measures under Order No. 1920, so long as they are consistent with the requirements stated above.

### F. Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities

#### 1. Logical Outgrowth

##### a. NOPR Proposals

718. In the NOPR, the Commission proposed to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities comply with the existing six Order No. 1000 regional cost allocation principles.[1811] The Commission made a preliminary finding that compliance with such principles will help ensure that Commission-jurisdictional rates resulting from any State Agreement Process will be just and reasonable and not unduly discriminatory or preferential.[1812] The six regional transmission cost allocation principles adopted in Order No. 1000 are: principle (1), the costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; principle (2), those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be

[1811] NOPR, 179 FERC ¶ 61,028 at PP 302, 312.

[1812] *Id.* P 312.

involuntarily allocated any of the costs of those transmission facilities; principle (3), a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; principle (4), costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; principle (5), the method for determining benefits and identifying beneficiaries must be transparent; and principle (6), there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[1813]

**b. Order No. 1920 Requirements**

719. In Order No. 1920, the Commission adopted the NOPR proposal, with modification, to require compliance with Order No. 1000 regional cost allocation principles (1) through (5) for Long-Term Regional Transmission Cost Allocation Methods that transmission providers propose but to which Relevant State Entities have not indicated their agreement. The Commission explained that, because compliance with regional cost allocation principle (6) is not required, transmission providers cannot adopt different *ex ante* Long-Term Regional Transmission Cost Allocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[1814]

[1813] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[1814] Order No. 1920, 187 FERC ¶ 61,068 at P 1469.

720. The Commission additionally determined that compliance with the Order No. 1000 regional cost allocation principles is not required in two situations: (1) Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed as part of the Engagement Period; and (2) cost allocation methods resulting from a State Agreement Process.[1815] The Commission explained that this decision was consistent with application of Order No. 1000 and past precedent, noting that the Commission has previously found that "Order No. 1000 allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s)."[1816] Additionally, the Commission noted that where transmission providers have proposed cost allocation methods corresponding to such voluntary arrangements, the Commission has held that it need not find that those cost allocation methods comply with Order No. 1000.[1817]

### c. Requests for Rehearing and Clarification

721. Several commenters argue that Order No. 1920 violates the APA's notice-and-comment requirements because, contrary to the NOPR proposal, it does not require cost allocation methods to comply with Order No. 1000's regional cost allocation principle (6)

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[1815] *Id.* P 1470.

[1816] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225, at P 3 (2021)).

[1817] *Id.* (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142-143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150, at P 121 (2013); *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106, at PP 48-50 (2022)).

and prohibits transmission providers from adopting different cost allocation methods for different types of transmission facilities.[1818] NRECA characterizes the change as an "about face" from both the NOPR and existing Commission policy.[1819]

722. NRECA additionally argues that Order No. 1920 violates the APA's notice-and-comment requirements because, contrary to the NOPR, Order No. 1920 does not require a transmission provider's Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles if Relevant State Entities indicate that they agreed to that method as part of the required Engagement Period, and does not require a cost allocation method resulting from the State Agreement Process to comply with any of the Order No. 1000 regional cost allocation principles.[1820] NRECA argues that the "Final Rule's flip-flops on these fundamental requirements for Long-Term Regional Transmission Cost Allocation Methods and the cost allocation methods resulting from a State Agreement Process are not a logical outgrowth of the NOPR's exactly opposite proposals."[1821]

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[1818] Arizona Commission Rehearing Request at 17-19; East Kentucky Rehearing Request at 1-2; NRECA Rehearing Request at 6, 16-17.

[1819] NRECA Rehearing Request at 16-17.

[1820] *Id.* at 6, 17.

[1821] *Id.* at 16-17.

### d. Commission Determination

723. We find, and disagree with rehearing requests to the contrary, that the Commission provided adequate notice of and opportunity to comment on the determination in Order No. 1920 to require transmission providers to demonstrate compliance with Order No. 1000 regional cost allocation principles (1) through (5) but not Order No. 1000 regional cost allocation principle (6) for Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed.

724. Courts applying the logical outgrowth doctrine have permitted agencies to drop elements of proposed rules "even if a resulting final rule effectively abandons an agency's initial proposal" if the result is "reasonably foreseeable."[1822] Order No. 1920 is a logical outgrowth of the NOPR in this regard, and the APA's notice-and-comment requirements are therefore satisfied.[1823] In the NOPR, the Commission expressed concern that transmission providers are not engaging in long-term, more comprehensive regional transmission planning and cost allocation processes like MISO's MVP process, which identifies projects that are projected to provide *multiple* kinds of reliability and economic benefits.[1824] The Commission proceeded to endorse this kind of transmission

[1822] *Mid Continent Nail Corp. v. U.S.*, 846 F.3d 1364, 1374 (Fed. Cir. 2017) (citing *Long Island Care*, 551 U.S. at 174-75).

[1823] *Id.* at 1373 ("The dispositive question in assessing the adequacy of notice under the APA is whether an agency's final rule is a 'logical outgrowth' of an earlier request for comment.").

[1824] NOPR, 179 FERC ¶ 61,028 at P 31.

planning.[1825] The Commission also noted expressly that "we preliminarily find that the cost allocation requirements for transmission facilities identified and selected in the regional transmission plan through Long-Term Regional Transmission Planning proposed in this proceeding may differ in part from those established in Order No. 1000."[1826]

725. But allowing transmission providers to establish reliability, economic, or public policy transmission facility types, which would have been possible under the NOPR proposal, reflects a more siloed approach to regional transmission planning and cost allocation that commenters argued is misaligned with the reforms in Order No. 1920 and urged the Commission to avoid.[1827] Indeed, the Commission specifically noted its concern that using "only a subset of benefits in assigning the cost of Long-Term Regional Transmission Facilities may contribute to the risk of free rider problems that impede development of the more efficient or cost-effective regional transmission facilities."[1828] That observation, which was made in the context of benefits used as the basis to allocate

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[1825] *Id.* P 33.

[1826] *Id.* P 299. Although the Commission then gave the example of greater state involvement as one way that the cost allocation requirements might differ, that statement was sufficient to put commenters on notice that the Commission would not necessarily adopt in full Order No. 1000's requirements regarding cost allocation. Indeed, as noted below, multiple commenters, including New Jersey Commission and PIOs, expressed support for modifying Order No. 1000's cost allocation principles, indicating their understanding that such potential modifications could be adopted in a final rule.

[1827] *See* Acadia Center and CLF NOPR Initial Comments at 16-17; Massachusetts Attorney General NOPR Initial Comments at 21; PIOs NOPR Initial Comments at 46, 60-62.

[1828] NOPR, 179 FERC ¶ 61,028 at P 325.

the costs of Long-Term Regional Transmission Facilities, further indicated the Commission's concerns with the siloed status quo approach and mirrored the rationale that the Commission adopted in eliminating regional cost allocation principle (6). It was therefore reasonably foreseeable that Order No. 1920 would not require compliance with regional cost allocation principle (6), which allows for project-type-limited Long-Term Regional Transmission Cost Allocation Methods, because such an approach would be inconsistent with Order No. 1920's long-term, forward-looking, more comprehensive regional transmission planning.[1829] However, as noted below, transmission providers and Relevant State Entities have broad flexibility to recognize the different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits.

726. Further, courts have held that a final rule satisfies the logical outgrowth standard where an agency either finalizes only part of a multi-segment proposal[1830] or chooses not to finalize a proposal.[1831] Order No. 1920 is a logical outgrowth of the NOPR in this

[1829] Order No. 1920, 187 FERC ¶ 61,068 at P 1474.

[1830] *Ariz. Pub. Serv. Co. v. EPA*, 211 F.3d at 1297–1300 (finding sufficient notice where agency first proposed that Indian tribes be required to meet the "same requirements" as states with respect to judicial review of permits issued pursuant to the Clean Air Act, but then adopted a final rule that exempted tribes from some, though not all, such requirements).

[1831] *New York v. EPA*, 413 F.3d at 44 (per curiam) ("One logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step." (quoting *Am. Iron & Steel Inst. v. EPA*, 886 F.2d at 400); *see also Long Island Care*, 551 U.S. at 175 (stating, in the context of rejecting claims that an agency provided legally defective notice because it did not finalize a proposed rule, "[w]e do not understand why such a possibility was not reasonably foreseeable"); *Vanda Pharms.*, 98 F.4th at 498 (finding that the APA's

regard. Because the NOPR proposed to require compliance with the existing six Order No. 1000 regional cost allocation principles, the Commission's decision to refrain from requiring compliance with one of those principles—principle (6)—could have been reasonably anticipated by commenters, especially given the Commission's frequently stated concerns regarding the siloing of transmission facilities into different categories under Order No. 1000.[1832] Indeed, in NOPR comments, parties expressed support for modifying Order No. 1000's cost allocation principles.[1833] Such comments are evidence that parties had adequate notice that the Commission might refrain from taking the NOPR's proposed step—i.e., requiring compliance with all six regional cost allocation principles.[1834]

727. For similar reasons, we also disagree that the Commission failed to provide adequate notice of and opportunity to comment on the determination in Order No. 1920 to not adopt the requirement that transmission providers demonstrate compliance with

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"notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content").

[1832] *See* NOPR, 179 FERC ¶ 61,028 at PP 67, 325.

[1833] New Jersey Commission NOPR Initial Comments at 18 (expressing support for a requirement that any cost allocation method comply with the Order No. 1000 regional cost allocation principles except principle (4)); PIOs NOPR Initial Comments at 61 & n.172 (requesting "that the Commission specifically find that cost allocation of public policy projects without consideration of economic and reliability benefits is unjust, unreasonable, and unduly discriminatory").

[1834] *Miami-Dade Cnty. v. EPA*, 529 F.3d 1049, 1059 (11th Cir. 2008) ("[A]lthough they may not provide the only basis upon which an agency claims to have satisfied the notice requirement, comments may be adduced as evidence of the adequacy of notice.").

any of the six Order No. 1000 regional cost allocation principles for Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed as part of the Engagement Period or for cost allocation methods resulting from a State Agreement Process. In the NOPR, the Commission proposed to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process comply with the six Order No. 1000 regional cost allocation principles.[1835] As noted above, because "[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step,"[1836] the Commission's decision to refrain from adopting the entire proposal as to Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed or for cost allocation methods resulting from a State Agreement Process could have been reasonably anticipated by commenters. Moreover, the decision to refrain from adopting the proposal was all the more foreseeable because, as a result of that decision, the cost allocation requirements adopted in Order No. 1920 are more closely aligned with the Commission's existing cost allocation requirements,[1837] which it had already articulated at the time it issued the NOPR, and under which cost allocation methods corresponding

[1835] NOPR, 179 FERC ¶ 61,028 at P 302.

[1836] *New York v. EPA*, 413 F.3d at 44.

[1837] *Cf. New York v. EPA*, 413 F.3d at 44 (agency satisfied APA's notice-and-comment requirements where it adopted the approach of the "status quo ante" rather than the proposed approach).

to voluntarily negotiated alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s) need not comply with Order No. 1000.[1838]

### 2. Omission of Regional Cost Allocation Principle No. 6 and Ability to Allocate Costs by Type of Project

#### a. Order No. 1920 Requirements

728. In Order No. 1920, the Commission declined to require transmission providers to demonstrate that any Long-Term Regional Transmission Cost Allocation Methods that they propose complies with Order No. 1000 regional cost allocation principle (6).[1839] The Commission explained that Order No. 1000 regional cost allocation principle (6) allows for cost allocation methods based on different types of transmission facilities (i.e., reliability, economic, or public policy transmission facility types), but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance.[1840] The Commission found that project-type-limited Long-Term Regional Transmission Cost Allocation Methods that would be permitted by applying regional cost allocation principle (6) are inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning required in Order No. 1920.[1841] As a result, unlike under Order No. 1000, transmission providers cannot adopt

[1838] Order No. 1920, 187 FERC ¶ 61,068 at P 1476 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142-143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 121).

[1839] *Id.* P 1469.

[1840] *Id.* P 1474.

[1841] *Id.*

different Long-Term Regional Transmission Cost Allocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[1842]

**b. Requests for Rehearing and Clarification**

729. Many parties argue that the Commission erred in not requiring the application of Order No. 1000 regional cost allocation principle (6) and request that the Commission implement such a requirement so that transmission providers may allocate the cost of Long-Term Regional Transmission Facilities by project type.[1843] Nearly all of these parties argue that not requiring the application of regional cost allocation principle (6) will result in cost allocation that violates cost causation or the "beneficiary pays" principle.[1844] Utah Commission asserts that the Commission not requiring the application of regional cost allocation principle (6) in Order No. 1920 violates cost causation

[1842] *Id.* P 1469.

[1843] Arizona Commission Rehearing Request at 18-19; Dominion Rehearing Request at 28-31; East Kentucky Rehearing Request at 3; Idaho Commission Rehearing Request at 2-4; Indicated PJM TOs Rehearing Request at 2-3, 4-6; Montana Commission Rehearing Request at 1, 4-6; Northern Virginia Rehearing Request at 5, 9-13; NRECA Rehearing Request at 49-55; Ohio Commission Federal Advocate Rehearing Request at 13-15; Utah Commission Rehearing Request at 9-10; West Virginia Commission Rehearing Request at 6-8; Wyoming Commission Rehearing Request at 4-6.

[1844] Arizona Commission Rehearing Request at 18-19; Idaho Commission Rehearing Request at 2-4; Indicated PJM TOs Rehearing Request at 2-3, 4-6; Montana Commission Rehearing Request at 1, 4-6; Northern Virginia Rehearing Request at 5, 9-13; NRECA Rehearing Request at 53-54; Utah Commission Rehearing Request at 9-10; West Virginia Commission Rehearing Request at 6-8; Wyoming Commission Rehearing Request at 4-6.

principles by flatly enjoining any cost allocation method that distinguishes between projects that are based on economic or engineering necessity and those based on the "public policy" preferences of states, local governments, and corporations.[1845] Several parties argue that Order No. 1920 will result in cost allocation that fails to reflect the role of state policy in causing costs and will shift the financial burden away from the cost-causing states that imposed those policies.[1846] Idaho Commission argues that Order No. 1920 contradicts the Commission's position in Order No. 1000, which stresses the role of states in consideration of costs potentially allocated across multiple states with respect to transmission needs driven by states' individual Public Policy Requirements.[1847]

730. Ohio Commission Federal Advocate argues that the prohibition against transmission providers allocating costs for Long-Term Regional Transmission Facilities based on reliability, economic, and Public Policy Requirement project types is not possible to reconcile with the principle that cost allocation ought to be roughly commensurate with benefits. Ohio Commission Federal Advocate offers as an example a transmission facility that would not exist but for the policy of one or more states, does not affect the power flow in any neighboring states, and does not provide any tangible benefit

[1845] Utah Commission Rehearing Request at 9-10.

[1846] Idaho Commission Rehearing Request at 3-4; Montana Commission Rehearing Request 5-6; West Virginia Commission Rehearing Request at 7-8; Wyoming Commission Rehearing Request at 5-6.

[1847] Idaho Commission Rehearing Request at 3 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486).

to any other states, arguing that the Commission ought to clarify that, in this instance, it is wholly appropriate that the sponsoring state or states bear the full cost of the facility and that it would be an unjust and unreasonable result to assign any costs to any other state. Ohio Commission Federal Advocate argues that Ohioans were not afforded the opportunity to weigh in on the policies of other states, nor were they granted a vote on the politicians enacting them, and, as such, should not be assigned any costs associated with those policies.[1848]

731. Some parties assert that the Commission's decision not to require the application of regional cost allocation principle (6) and the prohibition against Long-Term Regional Transmission Facility types and associated cost allocation methods is arbitrary and capricious[1849] because the Commission has not provided a reasonable explanation or any supporting evidence as to how, among other things, this policy will protect consumers from unjust, unreasonable, and unduly discriminatory transmission rates;[1850] the Commission did not explain how the rejection of project-type cost allocation is forward-looking or comprehensive;[1851] and the Commission did not meaningfully distinguish how Long-Term Regional Transmission Planning differs from regional transmission planning

[1848] Ohio Commission Federal Advocate Rehearing Request at 13-15.

[1849] *E.g.*, Northern Virginia Rehearing Request at 5.

[1850] East Kentucky Rehearing Request at 3.

[1851] Ohio Commission Federal Advocate Rehearing Request at 10.

under Order No. 1000.[1852] Dominion asserts that Order No. 1920 does not cite any record evidence, nor is it clear whether any commenters to the NOPR requested this change to Order No. 1000's cost allocation principles.[1853]

732. Dominion argues that Order No. 1920 inappropriately treats all Long-Term Regional Transmission Facilities as equal for cost allocation purposes under the guise of the holistic transmission planning that Order No. 1920 seeks to foster. Dominion further argues that holistic transmission planning can acknowledge that certain projects provide different types of benefits and serve different needs, but together, as a package, serve a variety of needs. Dominion asserts that, if cost allocation cannot be tied to an identified underlying driver for the project, costs are more likely to be inappropriately socialized to customers who did not cause the need and do not benefit from it. Dominion states that the Commission should continue to allow transmission providers to develop different project types and associated cost allocations, but also require that transmission providers have a category of projects to act as a backstop that accounts for all potential benefits.[1854]

733. NRECA argues that the Commission's argument in support of its prohibition on using different cost allocation methods for different types of Long-Term Regional Transmission Facilities is essentially that the Commission can restrict cost allocation

[1852] Dominion Rehearing Request at 29-30.

[1853] *Id.* at 29.

[1854] *Id.* at 29-31.

methods by dictating planning methods.[1855] NRECA contends that this prohibition and reasoning is contrary to precedent and the Order No. 1000 regional cost allocation principle (1) that Order No. 1920 adopts because it would result in the costs of transmission facilities being allocated in a manner that is not at least roughly commensurate with estimated benefits.[1856] NRECA argues that, if Long-Term Regional Transmission Facilities produce multiple types of benefits that must be accounted for in Long-Term Regional Transmission Planning, this is an argument for a more flexible and more tailored approach to cost allocation with different cost allocation methods, not a more prescriptive and less tailored approach.[1857]

734. NRECA contends that allocating costs of a Long-Term Regional Transmission Facility built to satisfy Public Policy Requirements or other expansive factors required by the rule, such as corporate commitments, in the same manner as a facility built for reliability or economic purposes also likely conflicts with Order No. 1000's regional cost allocation principle (2) because those that receive no benefits would likely be involuntarily allocated costs.[1858] NRECA argues that costs associated with Long-Term Regional Transmission Facilities built to satisfy transmission needs driven by corporate

[1855] NRECA Rehearing Request at 53.

[1856] *Id.* (citing *ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at P 622).

[1857] *Id.* at 54.

[1858] *Id.*

commitments should be borne by the relevant corporations, not by other transmission customers that do not benefit from the facility.[1859]

735. NRECA further argues that the omission of principle (6) and prohibition on using different cost allocation methods for different types of Long-Term Regional Transmission Facilities violates Order No. 1000's regional cost allocation principle (4) because it will likely allow the costs of Long-Term Regional Transmission Facilities built to satisfy a state's Public Policy Requirements to be allocated to customers in other states.[1860]

736. Arizona Commission, Ohio Commission Federal Advocate, and NRECA argue that the Commission's decision not to require the application of regional cost allocation principle (6) and the prohibition against Long-Term Regional Transmission Facility types and associated cost allocation methods replaces flexibility with a one-size-fits-all requirement.[1861] Idaho Commission contends that Order No. 1920 strays from Order No. 1000's "light touch," highlighted in *South Carolina Public Service Authority v. FERC*, where the Commission did not "dictate how costs are to be allocated."[1862]

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[1859] *Id.* at 55.

[1860] *Id.* Order No. 1000 regional cost allocation principle (4) provides that costs must be allocated "solely within th[e] transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs." Order No. 1000, 136 FERC ¶ 61,051 at P 657.

[1861] Arizona Commission Rehearing Request at 18-19; Ohio Commission Federal Advocate Rehearing Request at 14; NRECA Rehearing Request at 52, 54.

[1862] Idaho Commission Rehearing Request at 3 (quoting *S.C. Pub. Serv. Auth. v.*

737. Indicated PJM TOs request that the Commission clarify that, by precluding transmission providers from adopting Long-Term Regional Transmission Cost Allocation Methods for different project types, it did not intend to preclude transmission providers from adopting cost allocation methods that allocate costs based on the different benefits associated with a particular facility. Indicated PJM TOs argue that such a clarification would be consistent with the Commission's obligation to ensure that the transmission provider allocates the cost in a manner that is at least roughly commensurate with estimated benefits. Indicated PJM TOs state that, if the Commission does not grant this clarification, they seek rehearing of the decision to preclude transmission providers from adopting different Long-Term Regional Transmission Cost Allocation Methods based on a facility's benefits because this outcome is inconsistent with other statements in the NOPR and Order No. 1920 and long-standing cost causation principles and nothing in regional cost allocation principle (6) prevents transmission providers from having this flexibility.[1863]

738. Virginia and North Carolina Commissions argue that the Commission should afford transmission providers, in coordination with Relevant State Entities and other stakeholders, the maximum flexibility possible with respect to potential *ex ante* cost allocation methods, so long as such methods are in compliance with the Commission's cost-causation principles. As a result, Virginia and North Carolina Commissions assert

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*FERC*, 762 F.3d at 81).

[1863] Indicated PJM TOs Rehearing Request at 2-3, 4-6.

that the Commission should clarify on rehearing that Order No. 1920 does not expressly preclude cost allocation methods that allocate costs based on the incremental costs associated with the inclusion of one or more public policy factors.[1864]

### c. Commission Determination

739. We sustain Order No. 1920's decision to not require Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities do not agree to comply with Order No. 1000 regional cost allocation principle (6), and also sustain the prohibition of cost allocation methods that allocate costs based solely on one type of benefit, such as reliability, economic, and public policy transmission facility types. However, we note our clarification below that transmission providers and Relevant State Entities may consider different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits.[1865] Recognizing the flexibility to allocate costs in proportion to different types of benefits, we disagree with arguments raised on rehearing that the Commission should require the application of Order No. 1000 regional cost allocation principle (6) to Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed and arguments that the Commission's decision on this issue is arbitrary and capricious. First, because of the flexibility the Commission provided to transmission providers to propose different cost allocation methods for Long-Term Regional

[1864] Virginia and North Carolina Commissions Rehearing Request at 5-6.

[1865] *See infra* Concerns Regarding Cost Causation section.

Transmission Facilities, we disagree that a requirement not to use cost allocation methods that allocate costs based on project types will result in adoption of cost allocation methods that violate the cost causation principle. We reiterate that, as stated in Order No. 1920, the Commission will evaluate each proposed Long-Term Regional Transmission Cost Allocation Method to ensure that it will allocate costs in a manner that is at least roughly commensurate with the estimated benefits that Long-Term Regional Transmission Facilities will provide, which will ensure compliance with the cost causation principle and the just and reasonable standard more broadly.[1866] To the extent that a party believes that any Long-Term Regional Transmission Cost Allocation Method submitted on compliance, including those discussed herein, violates the cost causation principle, it will have the opportunity to raise those concerns in response to the compliance filing.

740. Additionally, as the Commission found in Order No. 1920, Long-Term Regional Transmission Facilities are likely to provide a diverse array of benefits,1867 and Order No. 1920 specifically required that transmission providers consider seven economic and

[1866] Order No. 1920, 187 FERC ¶ 61,068 at PP 1305 & n.2786, 1478; *see Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) ("Under the [FPA], electric utilities must charge 'just and reasonable' rates. For decades, the Commission and the courts have understood this requirement to incorporate a 'cost-causation principle'—the rates charged for electricity should reflect the costs of providing it." (internal citations omitted)); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("FERC and the courts have added flesh to these bare statutory bones [i.e., the just and reasonable standard], establishing what has become known in Commission parlance as the 'cost-causation' principle.").

[1867] Order No. 1920, 187 FERC ¶ 61,068 at PP 123, 126, 722.

reliability benefits,[1868] while not prohibiting them from also considering public policy benefits.[1869] We conclude that Long-Term Regional Transmission Facilities will likely have benefits beyond addressing transmission needs driven by Public Policy Requirements and allowing transmission providers to allocate costs based solely on one type of benefit, such as reliability, economic, or public policy transmission project types, would likely underestimate the benefits provided by the project and, for that reason, be inconsistent with the goals underlying long-term, forward-looking, more comprehensive regional transmission planning required in Order No. 1920.[1870]

741. Nevertheless, we emphasize the fundamental principle that costs must be allocated in a manner that is at least roughly commensurate with estimated benefits, ensuring that ratepayers will not pay for facilities from which they do not benefit.[1871] Regardless of the factors driving the need for that project, if a customer does not derive benefits from the project or if they derive only trivial benefits in relation to the project's costs, the customer cannot be forced to pay for the costs of the project without violating the cost causation principle.[1872]

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[1868] *See id.* PP 719-720.

[1869] *Id.* PP 737, 822; *see also id.* P 1515 & n.3220.

[1870] *Id.* P 1474.

[1871] *Id.* P 267.

[1872] *ICC v. FERC I*, 576 F.3d at 476-77; *ICC v. FERC III*, 756 F.3d at 564-65; *see Coal. of MISO Transmission Customers v. FERC*, 45 F.4th 1004, 1009 (D.C. Cir. 2022); *LSP Transmission Holdings II, LLC v. FERC*, 45 F.4th 979, 984 (D.C. Cir. 2022).

742. Additionally, contrary to Dominion's argument,[1873] the long-term, forward-looking, more comprehensive nature of Long-Term Regional Transmission Planning distinguishes it from regional transmission planning under Order No. 1000. Order No. 1000 did not establish similarly long-term, forward-looking, or comprehensive regional transmission planning requirements. As a result, the Commission engaged in reasoned decision-making in relying on the different attributes of Long-Term Regional Transmission Planning when not adopting Order No. 1000 regional cost allocation principle (6).

743. As the Commission also found in Order No. 1920, the application of Order No. 1000 regional cost allocation principles (1) through (5) safeguards against cost causation concerns. Notably, the Commission explained:

> [P]rinciples (1) and (2) require that benefits received are at least roughly commensurate with costs paid and that costs may not be involuntarily allocated to those that do not benefit, respectively. Further, Order No. 1000 regional cost allocation principle (5), as well as the requirements in this final rule to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities, ensures sufficient transparency for stakeholders to understand how the costs of selected Long-Term Regional Transmission Facilities will be allocated to transmission customers in relation to the benefits that they are forecasted to provide.[1874]

744. Therefore, even if a Long-Term Regional Transmission Facility helps to address a transmission need driven by a state or states' Public Policy Requirements, the costs of

[1873] Dominion Rehearing Request at 30.

[1874] Order No. 1920, 187 FERC ¶ 61,068 at P 1478.

that transmission facility will only be allocated to ratepayers in states without those Public Policy Requirements in relation to the benefits they receive. We note that the benefits of a transmission facility go beyond any particular need that it may address.[1875] As noted below, where Relevant State Entities agree, one potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation.[1876]

745. For these reasons, we disagree with rehearing arguments that seem to suggest that, for any Long-Term Regional Transmission Cost Allocation Method to satisfy the cost causation principle or, in NRECA's case, not contradict Order No. 1000 principles (1) and (2),[1877] transmission providers must disaggregate all disparate drivers of Long-Term Transmission Needs so that each identified Long-Term Regional Transmission Facility may precisely be attributed to a particular policy goal or other driver of the transmission

[1875] *See ICC v. FERC I*, 576 at 476 ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."). *See also* Order No. 1000, 136 FERC ¶ 61,051 at P 690 ("If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.").

[1876] *See infra* Concerns Regarding Cost Causation section.

[1877] NRECA Rehearing Request at 53-55.

need. As we emphasize throughout this section, transmission providers and Relevant State Entities have broad flexibility to develop cost allocation approaches, provided such approaches comply with the cost causation principle and are otherwise just and reasonable. Consistent with that flexibility, as we clarify below, transmission providers and Relevant State Entities are not precluded from considering in their proposed cost allocation methods the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. Nevertheless, we find that requiring transmission providers to conduct Long-Term Regional Transmission Planning in the manner suggested by NRECA might risk undermining the scaling of Long-Term Regional Transmission Facilities to provide a more efficient or cost-effective solution to multiple transmission needs by encouraging piecemeal transmission expansion (e.g., two separate transmission facilities to address two separate transmission needs may be more expensive than one facility meeting both needs) that caused the need for reform in the first place.[1878] In addition, that exercise would likely stymie transmission providers' selection of more efficient or cost-effective transmission solutions by leading them to ignore or otherwise discount the diverse range of benefits that Long-Term Regional Transmission Facilities can provide, likely leading them to underestimate the benefits that the facilities provide to customers.

[1878] Order No. 1920, 187 FERC ¶ 61,068 at PP 85, 112.

746. Moreover, we reiterate that Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed must satisfy Order No. 1000 regional cost allocation principles (1) through (5), such that transmission customers will only pay for Long-Term Regional Transmission Facilities (or portfolios of such Facilities) when the transmission provider has determined that they meet the transmission providers' selection criteria and transmission customers will only be allocated costs that are at least roughly commensurate with the estimated benefits they receive. As Order No. 1920 noted:

> [U]nder this final rule, customers pay for a more reliable and economic transmission system as identified through open and transparent Long-Term Regional Transmission Planning, and any state's ratepayers only fund the construction of Long-Term Regional Transmission Facilities that provide them with such benefits that are at least roughly commensurate with the costs of those facilities.[1879]

747. Consequently, and contrary to certain parties' arguments,[1880] these requirements will protect customers from unjust, unreasonable, and unduly discriminatory or preferential transmission rates.

748. Regarding NRECA's arguments that the cost allocation requirements of Order No. 1920 violate Order No. 1000 regional cost allocation principle (4),[1881] we disagree. NRECA's arguments are based on an incorrect interpretation of Order No. 1000 regional

[1879] *Id.* P 270.

[1880] *See e.g.*, East Kentucky Rehearing Request at 3.

[1881] NRECA Rehearing Request at 55.

cost allocation principle (4), which states that "[t]he allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that *transmission planning region* unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs."[1882] Order No. 1000 regional cost allocation principle (4) concerns transmission planning regions, not individual states as contemplated by NRECA's arguments, and it does not prohibit allocation of costs among customers in states within a single transmission planning region.

749. We disagree with rehearing parties who argue that the lack of a requirement to apply regional cost allocation principle (6), with its prohibition against adopting different Long-Term Regional Transmission Cost Allocation Methods for reliability, economic, and public policy transmission project types, creates a one-size-fits-all approach,[1883] inappropriately treats all Long-Term Regional Transmission Facilities as equal for cost allocation purposes,[1884] or otherwise conflicts with the Commission's "light touch" in Order No. 1000.[1885] In particular, NRECA is incorrect that the prohibition against adopting different Long-Term Regional Transmission Cost Allocation Methods for

[1882] Order No. 1000, 136 FERC ¶ 61,051 at P 657 (emphasis added).

[1883] *See* Arizona Commission Rehearing Request at 18-19; Ohio Commission Federal Advocate Rehearing Request at 14.

[1884] *See* Dominion Rehearing Request at 29-31.

[1885] *See* Idaho Commission Rehearing Request at 3; NRECA Rehearing Request at 52-53.

reliability, economic, and public policy transmission project types means that "transmission providers must similarly use a single cost allocation method."[1886] Rehearing parties' arguments focus on the prohibition against economic, reliability, and public policy types, but do not recognize the broad flexibility otherwise afforded under Order No. 1920's application of Order No. 1000 regional cost allocation principles (1)-(5) and allowance of multiple cost allocation methods for Long-Term Regional Transmission Facilities.[1887] Under Order No. 1920, transmission providers may craft different *ex ante* cost allocation methods to reflect the different proportion of benefits provided by Long-Term Regional Facilities with different underlying drivers.[1888] Thus, we clarify that Order No. 1920's prohibition against types is a prohibition against the allocation of costs based on a single category of benefits—whether reliability, economic, public policy, or another category of benefits. In other words, transmission providers could *not* allocate *all* costs of Long-Term Regional Transmission Facilities on the basis of public policy benefits, if doing so ignores economic and reliability benefits associated with those facilities. Allocating the costs of Long-Term Regional Transmission Facilities

[1886] NRECA Rehearing Request at 53.

[1887] Order No. 1920, 187 FERC ¶ 61,068 at P 1475 ("We clarify that this final rule does not preclude the adoption of multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection, i.e., is an *ex ante* cost allocation method, and does not allocate costs by project type.").

[1888] *Infra* Concerns Regarding Cost Causation section.

entirely on a single category of benefits would likely ignore the diverse range of benefits those Facilities likely provide, as described above, and in doing so violate the cost causation principle.

750. We reiterate the fact that Order No. 1920 provides flexibility previously unafforded in regional transmission planning both in the new types of compliant cost allocation methods (i.e., Long-Term Regional Transmission Cost Allocation Methods agreed to by Relevant State Entities during the Engagement Period and cost allocation methods resulting from a State Agreement Process) and in the lack of restrictions placed on these new state-agreed-to methods (i.e., the only requirement for such methods is compliance with the cost causation principle). We believe the possibilities afforded by state agreement under Order No. 1920 may address the concerns underlying rehearing parties' arguments.

751. Further, we grant Indicated PJM TOs' request for clarification that Order No. 1920 does not preclude transmission providers from adopting Long-Term Regional Transmission Cost Allocation Methods that allocate costs based on the different benefits associated with a particular Long-Term Regional Transmission Facility (or portfolio of Facilities).[1889] Transmission providers may propose *ex ante* Long-Term Regional Transmission Cost Allocation Methods that, for example, assign a portion of the costs of a Long-Term Regional Transmission Facility that are associated with reliability benefits to one set of beneficiaries, a portion of the costs associated with economic benefits to

[1889] Indicated PJM TOs Rehearing Request at 2-3, 4-6.

another set of beneficiaries, and a portion of costs associated with public policy benefits to a different set of beneficiaries. Such a method would not violate the Commission's decision to not apply regional cost allocation principle (6) because the Long-Term Regional Transmission Cost Allocation Method would not create a cost allocation method that is specific to, for example, a transmission facility that satisfies a transmission need driven by economic benefits. As such, elimination of Order No. 1000 regional cost allocation principle (6) does not yield as inflexible an outcome as rehearing partis assert.

752. In response to Virginia and North Carolina Commissions' request that the Commission clarify that Order No. 1920 does not preclude cost allocation methods that allocate costs based on the incremental costs associated with the inclusion of one or more public policy factors,[1890] we clarify that Order No. 1920's cost allocation requirements allow for, but do not require, transmission providers to account for the benefits associated with addressing transmission needs driven by Public Policy Requirements in any *ex ante* cost allocation method.[1891]

### 3. Concerns Regarding Cost Causation

#### a. Order No 1920 Requirements

753. In Order No. 1920, the Commission required Long-Term Regional Transmission Cost Allocation Methods not agreed to by Relevant State Entities to comply with Order No. 1000 regional cost allocation principles (1) through (5). The Commission found that

[1890] Virginia and North Carolina Commissions Rehearing Request at 5-6.

[1891] *See infra* Concerns Regarding Cost Causation section.

Order No. 1000 regional cost allocation principles (1) through (5) remain relevant for *ex ante* cost allocation methods for Long-Term Regional Transmission Facilities that transmission providers propose on compliance but for which Relevant State Entities have *not* indicated their agreement.[1892]

754. In Order No. 1920, the Commission did not require transmission providers to demonstrate that Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to or cost allocation methods resulting from a State Agreement Process comply with any of the Order No. 1000 regional cost allocation principles.[1893] The Commission chose not to adopt the NOPR proposal to require adherence to the six Order No. 1000 regional cost allocation principles in these circumstances because cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to are likely to facilitate agreement over development of such Long-Term Regional Transmission Facilities by, for example, making the Relevant State Entities more confident that customers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities and by reducing the likelihood that selected Long-Term Regional Transmission Facilities cannot be constructed because they do not receive necessary state regulatory

[1892] Order No. 1920, 187 FERC ¶ 61,068 at PP 1469, 1472-1473.

[1893] *Id.* PP 1470, 1476.

approvals.[1894] The Commission further reasoned that affording additional flexibility for these methods by not requiring the application of the six Order No. 1000 regional cost allocation principles may encourage their use, and consequently facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[1895] The Commission noted, however, that such methods must still be just and reasonable and not unduly discriminatory or preferential, and must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[1896] The Commission further explained that this decision was consistent with past precedent, noting that the Commission has previously found that "Order No. 1000 allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s)."[1897] Additionally, the Commission noted that where transmission providers have proposed cost allocation methods corresponding to such voluntary arrangements, the Commission has held that it need not find that those cost allocation methods comply with Order No. 1000.[1898] Consistent with this precedent,

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[1894] *Id.* P 1477.

[1895] *Id.*

[1896] *Id.* (citation omitted).

[1897] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3).

[1898] *Id.* (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142-143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 121; *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106 at PP 48-50).

the Commission found that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to and have asked transmission providers to file also qualify as voluntary alternative cost sharing arrangements and, accordingly, the Commission declined to require those methods to adhere to the six Order No. 1000 regional cost allocation principles.[1899] However, the Commission did require that any voluntary alternative cost sharing arrangements still comply with the cost causation principle and any other legal requirements for cost allocation.[1900]

**b. Requests for Rehearing and Clarification**

755. NRECA argues that Order No. 1920 does not provide a reasonable explanation for its decision not to require a Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles when Relevant State Entities indicate their agreement with such a method as part of the Engagement Period.[1901] NRECA further argues that Order No. 1920 similarly does not provide a reasonable explanation as to why the Commission did not require a cost allocation method resulting from a State Agreement Process to comply with the Order No. 1000 regional cost allocation principles.[1902] NRECA contends that neither Order No.

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[1899] *Id.*

[1900] *Id.*

[1901] NRECA Rehearing Request at 55.

[1902] *Id.* at 55-56.

1920's reliance on a 2021 Commission policy statement nor Order No. 1000 allows the Commission to waive the Order No. 1000 regional cost allocation principles as NRECA alleges the Commission does in the final rule.[1903] NRECA asserts that Order No. 1920's reference to prior instances where the Commission has approved voluntary agreements on a case-by-case basis without finding that their cost allocation methods comply with Order No. 1000 does not constitute precedent for a categorical waiver of Order No. 1000's requirements for future cost allocations methods reached under the State Agreement Process.[1904]

756. NRECA argues that Order No. 1920 adopts cost allocation requirements that are more prescriptive in some respects (e.g., prohibiting transmission providers from using different cost allocation methods for different project types) but less prescriptive in other respects (e.g., not requiring compliance with any Order No. 1000 regional cost allocation principles when states agree on a cost allocation method). NRECA contends that this results in opaque, lax, and inconsistent standards for cost allocation for Long-Term Regional Transmission Facilities. NRECA asserts that, as a result, the Commission will be unable to enforce the FPA's requirements against unjust, unreasonable, or unduly discriminatory or preferential rates.[1905]

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[1903] *Id.* at 56 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1476; *State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225).

[1904] *Id.* at 56-57 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1476 n.3150).

[1905] *Id.* at 52.

757. Arizona Commission argues that Order No. 1920 usurps Arizona's constitutional requirements that the Arizona Commission must apply rates that are fair and reasonable and that it must not recover costs from ratepayers that do not cause, or benefit from, a particular cost.[1906] Arizona Commission further argues that the cost allocation methods adopted in the final rule are contrary to existing ratemaking principles, which include providing customers with reliable power at the least cost and allocating costs to the entities that cause them.[1907] Ohio Consumers similarly claim that Order No. 1920 is arbitrary and capricious and violates policy and precedent that requires that costs be allocated consistent with those who receive benefits.[1908]

758. Virginia and North Carolina Commissions assert that the Commission must ensure public policies considered in planning criteria and scenarios are also appropriately accounted for in any *ex ante* cost allocation method to avoid cross-subsidization of state public policy goals. Virginia and North Carolina Commissions state that the Commission should clarify on rehearing that to comport with the Commission's cost-causation principles, any proposed *ex ante* cost allocation method must adequately account for not only the benefits resulting from an identified transmission project, but also the cost drivers (or cost causers) that contribute to the need for the transmission project. Alternatively, Virginia and North Carolina Commissions argue that the Commission

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[1906] Arizona Commission Rehearing Request at 20-21.

[1907] *Id.* at 20.

[1908] Ohio Consumers Rehearing Request at 9.

should expressly require the same public policy factors included in the Long-Term Scenarios to be considered as potential benefits for cost allocation purposes.[1909]

759. West Virginia Commission and Wyoming Commission argue that Order No. 1920's transmission planning and cost allocation requirements force transmission providers within their states to plan projects based on decarbonization goals of other states in the region.[1910] West Virginia Commission and Wyoming Commission further argue that this would require transmission providers in the state to account for abstract assumed benefits for its retail customers.[1911] West Virginia Commission and Wyoming Commission contend that, in the event that the costs allocated to retail customers exceed benefits that their respective state policies realize from regional transmission projects, they will be forced to assign unjust and unreasonable costs to retail customers or deny a utility a potentially significant portion of its expected cost recovery.[1912] Wyoming Commission argues that this result is contrary to core principles of utility regulation and

[1909] Virginia and North Carolina Commissions Rehearing Request at 3-4.

[1910] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1911] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1912] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7-8.

wrongfully empowers states to exact the costs of their policy initiatives from ratepayers in other states.[1913]

### c. Commission Determination

760. We disagree with NRECA's arguments that the Commission did not provide a reasonable explanation for its decision not to require cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file to comply with any of the Order No. 1000 regional cost allocation principles.[1914] We continue to find that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to are likely to facilitate agreement concerning development of such Long-Term Regional Transmission Facilities by, for example, making the Relevant State Entities more confident that customers in the state are receiving benefits at least roughly commensurate with their share of the costs of such facilities and by reducing the likelihood that selected Long-Term Regional Transmission Facilities cannot be constructed because they do not receive necessary state regulatory approvals.[1915] Further, we continue to find that affording additional flexibility for these methods may encourage their use, which would facilitate

[1913] Wyoming Commission Rehearing Request at 8.

[1914] NRECA Rehearing Request at 55-56.

[1915] Order No. 1920, 187 FERC ¶ 61,068 at P 1477.

the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[1916] In short, we find that the benefits of providing additional flexibility for state-agreed-upon cost allocation methods for Long-Term Regional Transmission Facilities outweigh NRECA's concerns regarding not applying the Order No. 1000 regional cost allocation principles, such that it represents a just and reasonable approach to these issues.

761. Additionally, we highlight that the cost causation principle and Commission precedent require the Commission to evaluate each proposed cost allocation method to determine whether it will allocate costs in a manner that is at least roughly commensurate with estimated benefits and whether the proposed method is just and reasonable and not unduly discriminatory or preferential, as stated in Order No. 1920.[1917] This is the case whether or not we specifically require these cost allocation methods to comply with the Order No. 1000 regional cost allocation principles.

762. For cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file, we continue to find that such methods qualify as voluntary alternative cost sharing arrangements, consistent with the Commission's previous findings that "Order No. 1000

[1916] *Id.* (citation omitted).

[1917] *See, e.g.*, *id.* P 1506 (citing *ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564).

allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s)"[1918] and that the Commission need not find that cost allocation methods corresponding to such voluntary agreements comply with Order No. 1000.[1919] Therefore, in response to NRECA, we continue to decline to require such cost allocation methods to adhere to the six Order No. 1000 regional cost allocation principles.[1920]

763. We further disagree with NRECA's arguments that the cost allocation requirements adopted in Order No. 1920 will result in inconsistent standards for cost allocation for Long-Term Regional Transmission Facilities and will result in the Commission's inability to enforce the FPA's requirements against unjust, unreasonable, and unduly discriminatory or preferential rates.[1921] We recognize that there are different requirements for cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file as compared to Long-Term Regional Transmission Cost Allocation Methods to which states

[1918] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3).

[1919] *Id.* (citing *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142-143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 121; *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106 at PP 48-50).

[1920] *Id.*

[1921] NRECA Rehearing Request at 52.

do not agree, but we find that the potential for differences is appropriate to give states flexibility.[1922] Regardless, we reiterate that all cost allocation methods must comply with the cost causation principle, as required by the FPA.[1923] Additionally, we note that nothing in FPA section 206 requires that transmission providers adopt the same or similar proposals on compliance provided that they comply with Order No. 1920.

764. We also disagree with arguments raised by Arizona Commission and Ohio Consumers on rehearing that Order No. 1920's transmission planning and cost allocation requirements are inconsistent with cost causation principles.[1924] All cost allocation methods for Long-Term Regional Transmission Facilities, including Long-Term Regional Transmission Cost Allocation Methods, regardless of whether they are agreed to by Relevant State Entities, and cost allocation methods resulting from Commission-approved State Agreement Processes, must comply with the cost causation principle and ensure that the costs of transmission facilities are allocated in a manner at least roughly commensurate with estimated benefits.[1925]

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[1922] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1477.

[1923] *Id.* P 1305 & n.2786.

[1924] Arizona Commission Rehearing Request at 20; Ohio Consumers Rehearing Request at 9.

[1925] Order No. 1920, 187 FERC ¶ 61,068 at PP 1305 & n.2786, 1506 (citing *ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564).

765. In light of our clarification noted below, we find it unnecessary, as requested by Virginia and North Carolina Commissions,[1926] to require transmission providers to demonstrate on compliance how both the benefits resulting from an identified transmission project and the cost drivers contributing to the need for that project are appropriately accounted for in their proposed Long-Term Regional Transmission Cost Allocation Method, or alternatively to require that the same public policy factors included in Long-Term Scenarios be considered as potential benefits for the purposes of cost allocation. Specifically, we note that our clarification regarding the recognition of benefits below in response to West Virginia Commission and Wyoming Commission's request may address Virginia and North Carolina Commissions' concerns regarding the consideration of public policy factors in cost allocation methods. Further, we find that requiring transmission providers to show that the relevant cost allocation methods comply with cost causation by ensuring that costs are allocated in a manner roughly commensurate with benefits will provide flexibility and account for regional diversity while also ensuring that those cost allocation methods comply with the requirements of the FPA.[1927]

766. We disagree with arguments raised on rehearing by West Virginia Commission and Wyoming Commission that Order No. 1920's transmission planning and cost allocation requirements force transmission providers within their states to plan

[1926] Virginia and North Carolina Commissions Rehearing Request at 3-4.

[1927] *See* Order No. 1920, 187 FERC ¶ 61,068 at 1510.

transmission projects based on decarbonization goals of other states in the transmission planning region and require transmission providers to account for abstract assumed benefits.[1928] First, as discussed above, because of the flexibility provided by the Commission regarding cost allocation, it is premature and speculative to assert that a requirement not to use cost allocation methods based on project type will result in adoption of cost allocation methods that violate cost causation principles. We also reiterate that, in the context of transmission facilities, the cost causation principle requires the Commission to ensure that any cost allocation method allocates costs in a manner roughly commensurate with estimated benefits, meaning that if consumers do not benefit from a project they will not be required to pay for it nor will they be required to bear a share of project costs that does not reflect their share of the project's benefits.[1929]

767. Further, we clarify that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion

[1928] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1929] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1305 & n.2786 ("The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits.") (citation omitted)); *ICC v. FERC I*, 576 F.3d at 476 ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."); *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 690 ("If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.").

to those benefits. As an example, one potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation. Under this potential cost allocation method, these costs and benefits could be identified based on one or more additional analyses, such as additional scenarios, run by the transmission providers for the purposes of informing cost allocation, e.g., scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. For example, the cost allocation method agreed to by the Relevant State Entities may allocate those incremental costs to states with those applicable laws, policies, and regulations.

768. Noting this clarification, and where Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities agree to are concerned, at the request of the Relevant State Entities in a multistate region, the following *ex ante* method for cost allocation may be proposed. In providing this example, we are not foreclosing other approaches for allocating the costs of Long-Term Regional Transmission Facilities on either an *ex ante* basis or through a State Agreement Process. Nor are we suggesting that cost allocation methods must adopt a similar approach to this framework in order to comply with the requirements of Order No. 1920. This example is as follows:

(1) For the purposes of cost allocation, transmission providers shall run an additional scenario analysis to identify transmission needs using the same Long-Term Scenarios and

sensitivities used in its Long-Term Regional Transmission Planning process, except that the inputs to such additional scenarios shall not include state laws, policies and regulations. Transmission providers shall identify transmission facilities to meet the needs identified in such additional scenario analysis and those facilities' costs. Transmission providers shall then determine the difference in costs between the set of Long-Term Regional Transmission Facilities selected in the regional transmission plan for purposes of cost allocation and the set of transmission facilities that would be selected based upon the additional scenario analysis.

(2) The portion of total selected Long-Term Regional Transmission Facility costs identified in (1) could be cost allocated according to an existing Commission-accepted cost allocation method that may be proposed on compliance with Order No. 1920.

(3) The amount representing the cost difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) shall be allocated as follows:

> a. The transmission providers shall identify by state the specific state laws, policies, and regulations that were used to plan and select the Long-Term Regional Transmission Facilities and shall quantify *by state* the specific costs of such Facilities.
>
> b. The costs identified in 3(a) shall be allocated solely to the state or states that are the sources of the policies used in planning and selection. The total difference between the costs of Long-Term Regional Transmission Facilities selected pursuant to the Long-Term Regional Transmission Planning process and (1) would be fully accounted for using this method of allocating costs among the states. For RTOs/ISOs, the cost allocation to transmission customers in a transmission pricing zone *within* a state would be developed by the applicable Transmission Owner(s). For non-RTOs/ISOs, the costs allocated to transmission customers in a

transmission provider's retail distribution service territory or footprint within a state would be developed by the applicable transmission provider.

### G. General Benefits Requirements Related to Cost Allocation

#### 1. Logical Outgrowth

##### a. NOPR Proposals

769. In the NOPR, the Commission proposed for consideration a list of Long-Term Regional Transmission Benefits for transmission providers to apply in Long-Term Regional Transmission Planning and cost allocation processes.[1930] Additionally, the Commission proposed to require that transmission providers identify on compliance the benefits they will use in any *ex ante* cost allocation method, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.[1931] The NOPR also proposed to require transmission providers to explain the rationale for using the benefits identified.[1932] Additionally, the Commission requested comment on the proposed requirements, whether the Commission should require that transmission providers account for the full list of benefits contained in the NOPR's Evaluation of the Benefits of Regional Transmission Facilities section, or whether no change to the benefits used in existing regional transmission processes was needed.[1933]

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[1930] NOPR, 179 FERC ¶ 61,028 at PP 185, 326.

[1931] *Id.* P 326.

[1932] *Id.*

[1933] *Id.* P 327.

### b. Order No. 1920 Requirements

770. In Order No. 1920, the Commission declined to adopt the NOPR proposal regarding the use of benefits in Long-Term Regional Transmission Cost Allocation Methods.[1934] Instead, as discussed above in the Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities section, the Commission required transmission providers in each transmission planning region to demonstrate that any Long-Term Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to complies with Order No. 1000 regional cost allocation principles (1) through (5). The Commission did not require transmission providers to demonstrate that Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to or cost allocation methods resulting from a State Agreement Process comply with any of the Order No. 1000 regional cost allocation principles, but the Commission noted that such methods must still be just and reasonable and not unduly discriminatory or preferential, and must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[1935] The Commission did not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a

[1934] Order No. 1920, 187 FERC ¶ 61,068 at P 1505.

[1935] *Id.* PP 1470, 1476-1477.

Long-Term Regional Transmission Cost Allocation Method filed with the Commission.[1936]

771. The Commission explained that the modified approach to the relationship of benefits used in Long-Term Regional Transmission Planning and Long-Term Regional Transmission Cost Allocation Methods provides transmission providers with flexibility to propose a Long-Term Regional Transmission Cost Allocation Method(s), allowing for negotiation in the Engagement Period, which the Commission believed will increase the likelihood that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective regional transmission solution will be developed. The Commission additionally explained that the requirements in Order No. 1920 to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities will provide transparency and help to ensure cost allocation is just and reasonable.[1937] Additionally, the Commission reasoned that this flexible approach is consistent with the approach the Commission took in Order No. 1000 and in subsequent orders on transmission providers' Order No. 1000 compliance filings, where the Commission allowed a wide variety of cost allocation methods and did not require that such methods specifically account for all benefits used in evaluation and selection processes.[1938]

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[1936] *Id.* P 1506.

[1937] *Id.*

[1938] *Id.* P 1507 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 560, 624).

### c. Requests for Rehearing and Clarification

772. NRECA contends that Order No. 1920's determination not to require transmission providers to disclose which benefits, if any, they use in their regional cost allocation proposals is not a logical outgrowth of the NOPR.[1939] NRECA argues that the requirement to use a stated set of benefits in evaluating and selecting Long-Term Regional Transmission Facilities, without requiring transmission providers to disclose which benefits were used in their regional cost allocation proposals, allows cost allocation to be "completely opaque and divorced from the measured benefits."[1940]

### d. Commission Determination

773. In response to NRECA's argument that the Commission violated the APA's notice-and-comment requirements by declining to adopt the NOPR proposal to require transmission providers to disclose the benefits used in Long-Term Regional Transmission Cost Allocation Methods, we note that certain clarifications adopted herein may alleviate the concerns underlying NRECA's argument. Specifically, as discussed in the Minimum Requirements section above, we clarify in this order that, once transmission providers make a selection decision, i.e., for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities) and the applicable cost allocation method is determined, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how those estimated

[1939] NRECA Rehearing Request at 12-13.

[1940] *Id.*

costs will be allocated, by zone (i.e., by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of the estimated benefits as imputed to each zone, as such benefits can be reasonably estimated, when a cost allocation method is agreed upon under a State Agreement Process or, if no State Agreement Process is used, at the time of project selection.

774. Noting this clarification, we nevertheless disagree with NRECA that the Commission violated the APA's notice-and-comment requirements. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a "logical outgrowth" of the proposed rule.[1941] Here, the NOPR proposed to require transmission providers to disclose the benefits used in Long-Term Regional Transmission Cost Allocation Methods after noting the Commission's concern that, among other things, the Commission's existing regional transmission planning and cost allocation requirements may result in transmission providers undervaluing the benefits of Long-Term Regional Transmission Facilities for purposes of allocating the costs of such facilities to beneficiaries in a manner that is roughly commensurate with estimated benefits.[1942] While Order No. 1920 did not adopt the NOPR proposal, it included safeguards that will ensure an adequate accounting for benefits in cost allocation methods

[1941] *Long Island Care*, 551 U.S. at 174-75. *See also Am. Paper Inst. v. EPA*, 660 F.2d at 959 n.13 ("An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given." (emphasis added)).

[1942] NOPR, 179 FERC ¶ 61,028 at PP 325-326.

for Long-Term Regional Transmission Facilities, in addition to the new safeguard we adopt in this order, noted above. For instance, Order No. 1920 noted that any cost allocation method for Long-Term Regional Transmission Facilities will be required to comply with cost allocation precedent, including that costs be allocated in a manner at least roughly commensurate with estimated benefits.[1943] That standard requires that transmission providers show, on compliance, that their proposed cost allocation methods match the allocation of costs associated with the project in a manner that is at least roughly commensurate with the estimated benefits of the project. We find that this approach is sufficiently similar, in practice, to the proposal in the NOPR that it can be said to "follow logically from" the NOPR, that the NOPR "adequately frame[d] the subjects for discussion,"[1944] and that "a reasonable member of the regulated class" could "anticipate the general aspects of the [final] rule."[1945]

### 2. Substantive Issues

#### a. Order No. 1920 Requirements

775. In Order No. 1920, the Commission required transmission providers in each transmission planning region to demonstrate on compliance that the required Long-Term

[1943] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 & n.2786 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87; Order No. 1000, 136 FERC ¶ 61,051 at P 10; *ICC v. FERC I*, 576 F.3d at 476).

[1944] *Conn. Light & Power Co. v. Nuclear Regul. Comm'n*, 673 F.2d at 533.

[1945] *Telesat Canada v. FCC*, 999 F.3d 707, 713 (D.C. Cir. 2021) (quotations omitted).

Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (i.e., reliability, economic, or transmission needs driven by Public Policy Requirements).[1946]

**b. Requests for Rehearing and Clarification**

776. Clean Energy Associations assert that the Commission should clarify the rights, obligations, and limits associated with transmission providers' adoption of multiple Long-Term Regional Transmission Cost Allocation Methods for comparable transmission facilities within its overall footprint. Further, Clean Energy Associations argue that the Commission should clarify that transmission providers must allocate the costs of similarly situated transmission facilities similarly to avoid undue discrimination and unjust and unreasonable rates.[1947] Clean Energy Associations assert that, although presently unclear, it seems plausible that under Order No. 1920, transmission providers could attempt to allocate the costs of two comparable transmission facilities (similar in costs and benefits) using entirely different methods if the transmission provider considers them to be different "types" of projects, based on any categorization rubric other than Order No. 1000's regional cost allocation principle (6).[1948] Clean Energy Associations

[1946] Order No. 1920, 187 FERC ¶ 61,068 at PP 1505-1506.

[1947] Clean Energy Associations Rehearing Request at 30-32.

[1948] *Id.* at 31.

also request clarification that Order No. 1920 does not preclude transmission providers from adopting a cost allocation approach that seeks to maximize net benefits.[1949]

777. Dominion seeks clarification on the consideration of the seven required benefits in cost allocation such that if a transmission provider opts to rely on all or some of the seven benefits in its cost allocation method, then it may apply different weighting to different benefits, e.g., based on probability of occurrence and certainty of benefit in later years.[1950]

### c. Commission Determination

778. We deny Clean Energy Association's request to clarify the rights, obligations, and limits associated with transmission providers' potential adoption of multiple Long-Term Regional Transmission Cost Allocation Methods for comparable transmission facilities within its overall footprint. Order No. 1920 provided guidance regarding transmission providers' use of multiple Long-Term Regional Transmission Cost Allocation Methods, including that transmission providers may adopt multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection and does

[1949] *Id.* at 32-33.

[1950] Dominion Rehearing Request at 26-27.

not allocate costs by project type (i.e., reliability, economic, or transmission needs driven by Public Policy Requirements).[1951]

779. In response to Clean Energy Associations' concern that transmission providers could attempt to allocate the costs of two comparable transmission facilities (similar in costs and benefits) using entirely different cost allocation methods if the transmission provider considers them to be different "types" of projects (other than those delineated in Order No. 1000's regional cost allocation principle (6)), we note that even if the costs of similar facilities are allocated using different cost allocation methods, the fundamental requirements associated with a just and reasonable rate (i.e., adherence to the cost causation principle and the requirement that costs be allocated in a manner that is at least roughly commensurate with estimated benefits) remain the same.1952 Therefore, a transmission provider may allocate the costs of two similar transmission facilities using different cost allocation methods and meet the requirements of Order No. 1920. In addition, we note that Order No. 1920 also does not preclude transmission providers from proposing on compliance a cost allocation approach that seeks to maximize net benefits.[1953]

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[1951] Order No. 1920, 187 FERC ¶ 61,068 at PP 1475, 1506. *See supra* P 749.

[1952] Order No. 1920, 187 FERC ¶ 61,068 at P 1305.

[1953] *See id.* P 964 ("We adopt the NOPR proposal, with modification, to require that transmission providers in each transmission planning region propose evaluation processes, including selection criteria, that seek to maximize benefits accounting for costs over time without over-building transmission facilities.").

780. Regarding Dominion's request for clarification that if a transmission provider opts to rely on all or some of the seven required benefits in its cost allocation method for Long-Term Regional Transmission Facilities, then it may apply different weighting to different benefits, we note that Order No. 1920 includes no limitation on weighting of the seven required benefits for purposes of accounting for such benefits in the cost allocation method for Long-Term Regional Transmission Facilities save that costs must be allocated in a manner that is at least roughly commensurate with estimated benefits. Further, transmission providers can consider additional benefits for cost allocation purposes, including, but not limited to, those agreed to by Relevant State Entities and those described elsewhere in Order No. 1920, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

### H. Additional Cost Allocation Issues

#### 1. Order No. 1920 Requirements

781. In Order No. 1920, the Commission declined to adopt a particular time frame for determining the cost allocation for a Long-Term Regional Transmission Facility. The Commission stated that imposing a standardized time frame to determine cost allocation was unnecessary and could impede the regional flexibility that the Commission provided to transmission providers under Order No. 1920. The Commission added, however, that the determination of the applicable cost allocation must occur by or before selection of a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) if

only a Long-Term Regional Transmission Cost Allocation Method is available for that Facility (or portfolio of such Facilities).[1954]

782. Also in Order No. 1920, the Commission stated that, following the Engagement Period, Relevant State Entities may agree to, and ask the transmission providers to file, a State Agreement Process, which, if accepted by the Commission, would be the cost allocation process used by the transmission providers in the transmission planning region prior to using the relevant Long-Term Regional Transmission Cost Allocation Method as a backstop.[1955] Further, in response to NOPR comments requesting that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods, the Commission in Order No. 1920 found that any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent, and noted that the Commission will evaluate whether a proposed cost allocation method satisfies this standard on a fact-specific basis, relying on the record in a given proceeding. The Commission found that load ratio share, which charges transmission customers in proportion to their use of the transmission system as measured by their relative share of

[1954] *Id.* P 1521.

[1955] *Id.* P 1296.

load, is a cost allocation method that may be consistent with the beneficiary-pays approach.[1956]

783. Separately, in Order No. 1920, the Commission found that commenters' statements regarding cost containment were outside the scope of the proceeding.[1957] The Commission noted that it is examining issues related to transmission planning and cost containment in other proceedings.[1958]

### 2. Requests for Rehearing and Clarification

784. Dominion seeks clarification regarding the deadline imposed by Order No. 1920's requirement that "the determination of the applicable cost allocation must occur by or before its selection."[1959] Dominion avers that this requirement implies that there could be situations "when a Long-Term Regional Transmission Facility Cost Allocation Method would not be applied to a Long-Term Regional Transmission Facility."1960 Dominion states that its understanding is that "a Long-Term Regional Transmission Facility Cost

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[1956] *Id.* P 1305 (citations omitted).

[1957] *Id.* P 1523. Specifically, the Commission was responding to comments by: (1) Joint Commenters in support of a cost management framework overseen by the Commission; and (2) State Water Contractors, who asserted that the need for cost containment is acute for consumers in California and an essential component of the justness and reasonableness of any final rule. *Id.* P 1518.

[1958] *Id.* P 1523 (citing Supplemental Notice of Technical Conference, Transmission Planning and Cost Management, Docket No. AD22-8-000 (Oct. 4, 2022)).

[1959] Dominion Rehearing Request at 32 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1521).

[1960] *Id.* (emphasis omitted).

Allocation Method must be used, and that method could be one of several methods: the Transmission Provider's default *ex ante* cost allocation method, some other approved *ex ante* cost allocation method, or a State Agreement Process."1961 Dominion requests that, to the extent the Commission was referring to the deadline of six months after project selection for submission of cost allocation methods resulting from a State Agreement Process, the Commission provide clarification.[1962]

785. Dominion further asks the Commission to clarify whether only the cost allocation method must be determined by project selection, or whether it must be applied (and costs actually allocated) by project selection. Dominion notes its understanding is that only the method must be determined by selection and states that this clarification on timing would help to alleviate the concern about the challenges transmission developers will face in obtaining state regulatory approval for transmission projects designed to meet a predicted need 20 years in the future. Specifically, Dominion states that it is impossible to meet even a "roughly commensurate" standard when projected beneficiaries subject to the cost allocation decision are so far removed from the in-service date of the facilities, particularly in the context of an RTO/ISO in which transmission owning entities are permitted to leave and join.[1963]

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[1961] *Id.*

[1962] *Id.* at 32-33.

[1963] *Id.* at 31, 33-34.

786. Designated Retail Regulators and Undersigned States argue that any Long-Term Regional Transmission Cost Allocation Method should not include a postage-stamp-type cost allocation, as the costs imposed on non-consenting states should be allocated to cost causers and beneficiaries on as granular a basis as possible. They further argue that postage stamp-type cost allocation method should not be adopted merely to simplify the work of an RTO and to facilitate the construction of such projects.[1964]

787. Wyoming Commission asserts that if a portion of the costs of a Long-Term Regional Transmission Facility are to be recovered from Wyoming retail customers, the Wyoming Commission must evaluate the costs and benefits derived from the project on a *post hoc* basis to determine that costs allocated to retail customers and rates designed to recover those costs are just and reasonable. Wyoming Commission avers that Order No. 1920 does not accommodate this process.[1965]

788. Industrial Customers request rehearing of Order No. 1920's finding that commenters' statements regarding cost containment are outside the scope of this proceeding, arguing that such a finding is arbitrary and capricious because the Commission failed to meaningfully engage arguments and evidence supporting the current need for cost management and cost containment. According to Industrial Customers, while the Commission in Order No. 1920 stated that it is examining issues

[1964] Designated Retail Regulators Rehearing Request at 39; Undersigned States Rehearing Request at 34.

[1965] Wyoming Commission Rehearing Request at 8.

related to transmission planning and cost containment in other proceedings, Order No. 1920 does not compel the Commission to act in the proceeding in Docket No. AD22-8-000, which is the only pending proceeding that is sufficiently broad to complement Order No. 1920. Industrial Customers add that Order No. 1920 does not demonstrate that cost containment and cost mitigation measures are unrelated to the cost issues at hand or are, in fact, outside the scope of Order No. 1920.[1966]

### 3. Commission Determination

789. Regarding Dominion's request for clarification regarding the intent of the requirement that "the determination of the applicable cost allocation must occur by or before its selection,"[1967] we clarify that this requirement applies only to Long-Term Regional Transmission Cost Allocation Methods. We further clarify that Long-Term Regional Transmission Cost Allocation Methods refer only to *ex ante* cost allocation methods used to allocate the costs of selected Long-Term Regional Transmission Facilities.[1968]

790. Dominion requested clarification as to whether "the determination of the applicable cost allocation must occur by or before its selection"[1969] means that only the

[1966] Industrial Customers Rehearing Request at 21-23 (citing *State Farm*, 463 U.S. at 43).

[1967] Order No. 1920, 187 FERC ¶ 61,068 at P 1521.

[1968] *Id.* P 1291.

[1969] *Id.* P 1521.

cost allocation method must be determined by a Long-Term Regional Transmission Facility's selection or whether it must be applied (and costs actually allocated) by project selection. Noting our clarification above that this requirement applies only to Long-Term Regional Transmission Cost Allocation Methods, we clarify that Dominion is correct that only the applicable cost allocation method must be determined by project selection. While it is possible that certain Long-Term Regional Transmission Cost Allocation Methods will be designed in a way that actual costs to be allocated may be known by selection, such a requirement would needlessly limit the flexibility provided to transmission providers and could, in particular, create unnecessary obstacles to transmission providers' ability pursuant to Order No. 1920 to demonstrate that use of existing cost allocation methods to allocate the cost of Long-Term Regional Transmission Facilities would be compliant with Order No. 1920's requirements.[1970]

791. We are not persuaded by arguments raised by Designated Retail Regulators and Undersigned States regarding postage-stamp cost allocation. As in Order No. 1920,[1971] we continue to find that the record does not support a blanket prohibition on postage-stamp-type cost allocation. We will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits

[1970] For example, requiring that actual costs be allocated would preclude transmission providers from proposing that DFAX-based or postage-stamp cost allocation methods comply with Order No. 1920 because the amounts each transmission customer will pay are not known at the time of selection for those methods.

[1971] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 (citing Certain TDUs NOPR Initial Comments at 2, 7, 8-9; R Street NOPR Initial Comments at 4, 12).

on a case-specific basis, relying on the record to ensure that it complies with the cost-causation principle by allocating costs in a manner that is at least roughly commensurate with estimated benefits. We continue to find that the flexibility that we provide to consider benefits in cost allocation does not prevent transmission providers in a particular transmission planning region from adopting a more granular approach.[1972]

792. In response to Wyoming Commission, we reiterate that Order No. 1920 does not change existing mechanisms for cost-recovery through retail rates.[1973] We also emphasize that Order No. 1920 neither aims at nor conflicts with state authority over retail rates.[1974] However, we decline to modify Order No. 1920 to enable states to conduct a *post hoc* review of costs allocated to retail customers. Order No. 1920 does not alter the requirement for states to pass through Commission-jurisdictional rates to retail customers.[1975]

793. Finally, we disagree with Industrial Customers that the Commission failed to engage in reasoned decision making by determining that various NOPR comments regarding cost containment were outside the scope of the proceeding. First, to the extent

[1972] *Id.* P 1512.

[1973] *Id.* P 259.

[1974] *Id.* P 998.

[1975] *See Narragansett Elec. Co. v. Burke,* 381 A.2d 1358, 1361-63 (R.I. 1977) (holding that the state could not inquire into the reasonableness of the Commission-approved wholesale rate and, consequently, must treat it as a reasonable operating expense in the company's retail cost of service).

that Industrial Customers are arguing that the Commission did not consider transmission-related costs to consumers, as noted above, addressing costs to ratepayers was central to the reforms the Commission adopted in Order No. 1920, and the Commission cited evidence that more comprehensive, longer-term regional transmission planning results in the selection of more efficient or cost-effective transmission solutions, which has significant benefits for customers.[1976] Second, the NOPR did not propose to address cost containment reform per se, and we continue to find that certain comments regarding cost containment reform, including those proposing a specific cost management framework, are outside the scope of this proceeding.[1977] Third, we are unpersuaded by Industrial Customers' unsupported argument that the Commission was required to make a binding commitment to finalize cost containment and cost mitigation measures in another docket—we are unaware of any such requirement. Finally, we disagree that Order No. 1920 is arbitrary and capricious because it failed to meaningfully engage with arguments and evidence supporting the need for transmission cost management and cost containment, in contravention of *State Farm.*[1978] *State Farm*, which held that rescission of a prior regulation was arbitrary and capricious because it was done without adequate

[1976] *See supra* The Overall Need for Reform section.

[1977] Order No. 1920, 187 FERC ¶ 61,068 at P 1523.

[1978] Industrial Customers Rehearing Request at 23 (citing *State Farm*, 463 U.S. at 43).

explanation,[1979] did not hold that every aspect of a problem within an agency's jurisdiction must be addressed in a single rulemaking, or that a final rule must include requirements that address comments that were outside the scope of the proceeding.[1980]

## IX. Construction Work in Progress Incentive

### A. CWIP

#### 1. Order No. 1920

794. In Order No. 1920, the Commission declined to act to finalize the NOPR proposal to not permit transmission providers to take advantage of the allowance for inclusion of 100% of Construction Work in Progress (CWIP) costs in rate base (CWIP Incentive) for Long-Term Regional Transmission Facilities.[1981] The Commission concluded that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives after the Commission has finalized its Long-Term Regional Transmission Planning reforms.[1982] The Commission found that, in particular, whether the Commission's incentives are appropriately "benefitting consumers by ensuring reliability and reducing the cost of delivered power"

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[1979] *State Farm*, 463 U.S. at 34.

[1980] *See N.Y. v. FERC*, 535 U.S. at 27 (holding that "[b]ecause FERC determined that the remedy it ordered constituted a sufficient response to the problems FERC had identified in the wholesale market, FERC had no [FPA section] 206 obligation" to adopt further reforms).

[1981] Order No. 1920, 187 FERC ¶ 61,068 at PP 1524, 1547.

[1982] *Id.* P 1547.

is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.[1983]

### 2. Requests for Rehearing and Clarification

795. Several parties request rehearing on the grounds that the Commission failed to conduct reasoned decision-making in declining to act to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities.[1984] NARUC, for instance, states that the Commission not only failed to rebut arguments that ratepayers will have to pay in advance for facilities that may not ever be used, but also simply declined to finalize the NOPR proposal until the Commission can address other incentives at the same time, which NARUC contends is not reasoned decision-making.[1985] Ohio Consumers agree, and argue that retaining the CWIP Incentive for Long-Term Regional Transmission Facilities without an analysis on the justness and reasonableness of rates of return is arbitrary and capricious.[1986]

796. Some parties argue on rehearing that not adopting the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities will shift risks to ratepayers.[1987] Ohio Consumers state that the failure of the Commission to

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[1983] *Id.* (quoting 16 U.S.C. 824s(a)).

[1984] Industrial Customers Rehearing Request at 24, 26; NARUC Rehearing Request at 5, 8, 10-11; Ohio Consumers Rehearing Request at 11-12.

[1985] NARUC Rehearing Request at 9-11.

[1986] Ohio Consumers Rehearing Request at 12.

[1987] NARUC Rehearing Request at 8-9; Ohio Consumers Rehearing Request at 11;

eliminate the CWIP Incentive for Long-Term Regional Transmission Facilities shifts the risk of long-term transmission planning to consumers who may never benefit from a project if it does not go into service, but who will still be required to pay for it.[1988]

797. Certain parties request that, if the Commission does not grant rehearing in this proceeding and eliminate the CWIP Incentive for Long-Term Regional Transmission Facilities, the Commission should move quickly to address the CWIP Incentive in a separate proceeding.[1989] For instance, Virginia Attorney General implores the Commission to act with expediency to scale back transmission incentives comprehensively in Docket No. RM20-10-000, or another docket as appropriate, if the Commission does not grant rehearing in this proceeding and limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities.[1990]

798. Arizona Commission argues that "walk[ing] back" the proposal to disallow the CWIP Incentive is not a logical outgrowth of the NOPR, and failure to provide for

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Virginia Attorney General Rehearing Request at 4-5; West Virginia Commission Rehearing Request at 16-17; *see* Designated Retail Regulators Rehearing Request at 42.

[1988] Ohio Consumers Rehearing Request at 11-12.

[1989] Designated Retail Regulators Rehearing Request at 42-43; Industrial Customers Rehearing Request at 28; PJM States Rehearing Request at 9; Virginia Attorney General Rehearing Request at 5; West Virginia Commission Rehearing Request at 17; *see also* Identified Consumer Advocates Rehearing Request at 4, 8-9.

[1990] Virginia Attorney General Rehearing Request at 5.

additional notice and comment on this "fundamental" change is a direct violation of the APA.[1991]

### 3. Commission Determination

799. We are unpersuaded by arguments raised on rehearing that the Commission erred by failing to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities. We continue to find that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives,[1992] and we disagree with parties that argue that the Commission's decision in Order No. 1920 to defer acting on the CWIP Incentive was arbitrary and capricious. The Commission reviewed all of the comments received on this proposal in response to the NOPR and concluded that whether the Commission's transmission incentives, including the CWIP Incentive, are appropriately "benefitting consumers by ensuring reliability and reducing the cost of delivered power" is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.[1993] We continue to reach this conclusion and find that evaluating a single transmission incentive for a regional

[1991] Arizona Commission Rehearing Request at 17-19 (citing 5 U.S.C. 706(2)(A), (2)(C), (2)(D)).

[1992] Order No. 1920, 187 FERC ¶ 61,068 at P 1547.

[1993] *Id.* (quoting 16 U.S.C. 824s(a)).

transmission facility may fail to holistically consider benefits and risks to consumers from transmission incentives.

800. Further, with respect to the argument that the Commission's decision declining to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities was not a logical outgrowth of the NOPR, we disagree. As courts have explained, "[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step."[1994] The same is true here. We acknowledge the interest and support for evaluating the CWIP Incentive, particularly among several states, along with other transmission incentives, and note that the Commission will continue to evaluate the appropriate manner for considering transmission incentives, including the CWIP Incentive, for all regional transmission facilities.

## X. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements

### A. Order No. 1920 Requirements

801. In Order No. 1920, the Commission stated that, after careful consideration of the record, it was declining to finalize the NOPR proposal to amend Order No. 1000's findings and nonincumbent transmission developer reforms, in part, to permit the

[1994] *New York v. EPA*, 413 F.3d at 44 (quoting *Am. Iron & Steel Inst. v. EPA*, 886 F.2d at 400); *see also Long Island Care*, 551 U.S. at 175 (stating, in the context of rejecting a claim that an agency provided legally defective notice because it did not finalize a proposed rule, "[w]e do not understand why such a possibility was not reasonably foreseeable"); *Vanda Pharms.*, 98 F.4th at 498 (stating that the APA's "notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content").

exercise of federal rights of first refusal for selected regional transmission facilities, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR. The Commission stated that it will continue to consider potential federal right of first refusal reforms along with other transmission reforms in the future.[1995]

### B. Request for Rehearing

802. NRECA states that declining to adopt the NOPR's conditional federal right of first refusal proposal was a missed opportunity because it would have encouraged transmission providers to pursue planning and expanding transmission through joint ownership arrangements with load-serving entities.[1996]

### C. Commission Determination

803. The Commission explained in Order No. 1920 that it will continue to consider the NOPR proposal and potential federal rights of first refusal issues in other proceedings, a course of action we continue to find to be reasonable.[1997] As noted in Order No. 1920, comments on the NOPR raised both concerns about whether incumbent transmission

[1995] Order No. 1920, 187 FERC ¶ 61,068 at PP 1548, 1563-1564.

[1996] NRECA Rehearing Request at 2.

[1997] Order No. 1920, 187 FERC ¶ 61,068 at PP 1563-1564. NRECA did not request rehearing on this issue or include it in NRECA's Statement of Issues. *See* 18 CFR 385.713(c)(2) (any issue not listed in the Statement of Issues will be deemed waived). We nevertheless address NRECA's concern.

providers face perverse investment incentives due to Order No. 1000's reforms and concerns about whether the NOPR proposal would adequately and appropriately address those incentives.[1998]

## XI. Local Transmission Planning Inputs in the Regional Transmission Planning Process

### A. Need for Reform

#### 1. Order No. 1920

804. In Order No. 1920, the Commission found substantial evidence to support the conclusion that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential.[1999] Therefore, the Commission adopted the NOPR findings that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders, and that regional transmission planning processes may not adequately coordinate with local transmission planning processes.[2000]

805. The Commission explained that local and regional transmission planning processes serve essential and complementary roles in ensuring that customers' transmission needs are identified and met at a just and reasonable cost.[2001] The

[1998] Order No. 1920, 187 FERC ¶ 61,068 at P 1564.

[1999] Order No. 1920, 187 FERC ¶ 61,068 at PP 1565, 1569.

[2000] *Id.* P 1569.

[2001] *Id.* P 1570.

Commission added that information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning, and it is therefore critical that the processes are appropriately designed and aligned to ensure that transmission providers and stakeholders have the information needed, including from the local transmission planning process, to conduct effective regional transmission planning.[2002] Additionally, the Commission stated that, while the broader reforms directed in Order No. 1920 are focused on improving the regional transmission planning process, there are discrete deficiencies in the local transmission planning process and its coordination with the regional transmission planning process that must be addressed to ensure Commission-jurisdictional rates are just and reasonable.[2003]

806. The Commission first found that local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders. The Commission recognized the critical role stakeholders serve in effective transmission planning,[2004] and noted prior reforms to facilitate their meaningful participation in both local and regional transmission planning.[2005] However, the Commission found that the record demonstrates that existing transparency and coordination requirements in local

[2002] *Id.* P 1570.

[2003] *Id.* P 1570.

[2004] *Id.* P 1571 (citing Order No. 890, 118 FERC ¶ 61,119 at P 454; Order No. 1000, 136 FERC ¶ 61,051 at P 152).

[2005] *Id.* (citing Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152.).

transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.[2006] The Commission found that the absence of minimal standards or specified procedures to implement the transmission planning principles required by Order No. 890 contributes to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.[2007] The Commission explained that the combined effect of these deficiencies is that stakeholders who wish to participate in transmission planning, at both the local and regional level, may not be able to effectively do so. More specifically, the Commission found that, when engaging in the regional transmission planning process, stakeholders lack sufficient information about underlying local transmission needs and potential solutions that is necessary to ensure that the more efficient or cost-effective regional transmission solutions are identified, evaluated, and selected.[2008] The Commission stated that, given the importance of stakeholder participation in effective transmission planning, reforms were needed to ensure that Commission-jurisdictional local and regional transmission planning processes remain just, reasonable, and not unduly discriminatory or preferential.[2009]

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[2006] *Id.* (citations omitted).

[2007] *Id.*

[2008] P 1572.

[2009] *Id.*

807. The Commission also concluded that additional coordination between the local and regional transmission planning processes regarding the replacement of aging infrastructure is needed. The Commission found that the record showed that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life. The Commission specifically noted that, in PJM and NYISO, a significant portion of transmission assets either need to be replaced or will soon need to be replaced.[2010] The Commission stated that replacing these transmission facilities will require substantial investment, which will directly affect Commission-jurisdictional rates.[2011]

808. The Commission stated, however, that because its existing requirements do not obligate transmission providers to share sufficient information regarding these replacement projects, transmission providers in the regional transmission planning process are not consistently evaluating whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission system needs.[2012] Therefore, the Commission concluded, the lack of a requirement for transmission providers in each transmission planning region to evaluate whether those replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address Long-Term Transmission Needs results in a

[2010] *Id.* P 1573 (citations omitted).

[2011] *Id.*

[2012] *Id.* P 1574.

regional transmission planning process that fails to identify opportunities to right-size planned in-kind replacement transmission facilities and may result in the development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.[2013]

809. The Commission disagreed with claims from commenters that the Commission lacked jurisdiction to impose the requirements in Order No. 1920 or that the Commission did not justify those requirements.[2014] The Commission explained that consistent with Order Nos. 890 and 1000, the Commission has the authority to establish requirements related to local transmission planning processes and the inputs to regional transmission planning processes.[2015]

810. In response to claims from commenters questioning whether the Commission properly demonstrated under FPA section 206 that existing rates are unjust, unreasonable, or unduly discriminatory or preferential in instituting a federal right of first refusal for right-sized replacement transmission facilities, the Commission explained that it found transmission providers' OATTs to be unjust and unreasonable due to the lack of right-

[2013] *Id.* P 1574.

[2014] *Id.* P 1575 (citations omitted).

[2015] *Id.* (citing Order No. 890, 118 FERC ¶ 61,119 at P 435; Order No. 1000, 136 FERC ¶ 61,051 at PP 68, 148, 1520).

sizing requirements that may lead to the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[2016]

811. Because the Commission found that existing requirements governing transparency in the local transmission planning process and coordination between local and regional transmission planning processes were insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, the Commission required, pursuant to FPA section 206, transmission providers to adopt, with modifications, the two reforms the Commission identified in the NOPR: (1) enhance the transparency of the local transmission planning process; and (2) require transmission providers to evaluate whether transmission facilities that need replacing can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.[2017] The Commission found that the first reform will result in transmission providers providing enhanced transparency for stakeholders while providing those same stakeholders with opportunities to more effectively engage in local and regional transmission planning processes. The Commission found that the second reform will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Finally, the Commission found that, taken together, these reforms

[2016] *Id.* P 1576 (citations omitted).

[2017] *Id.* P 1577.

will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[2018]

812. On rehearing, several parties challenge the Commission's findings. We address their arguments below.

### 2. Analysis under FPA Section 206

#### a. Rehearing Requests

813. Advanced Energy and Competition Coalition contend that the Commission failed to engage in reasoned decision-making, in violation of the APA and the required analysis under FPA section 206, by ignoring relevant considerations, failing to address applicable precedent, and inadequately explaining its decision to grant incumbent transmission providers a right of first refusal for right-sized replacement transmission facilities.[2019] Competition Coalition adds that the Commission has failed to prove that the reform is just and reasonable, supported by substantial evidence, the product of reasoned decision-making, and consistent with the public interest.[2020]

814. Competition Coalition, Industrial Customers, and Designated Retail Regulators request rehearing on the grounds that, in adopting the reforms in Order No. 1920 regarding enhanced transparency of local transmission planning inputs and identifying

[2018] *Id.*

[2019] Advanced Energy Rehearing Request at 4; Competition Coalition Rehearing Request at 8.

[2020] Competition Coalition Rehearing Request at 59-60.

opportunities to right-size replacement transmission facilities, the Commission failed to satisfy the requirement to make a finding, supported by substantial evidence, that the existing relevant tariff provisions result in rates that are unjust, unreasonable, or unduly discriminatory.[2021] Competition Coalition and Industrial Customers, for example, argue that Order No. 1920 does not support with substantial evidence the Commission's claim that the interrelationship between local and regional transmission planning yields unjust, unreasonable, or unduly discriminatory rates, and therefore does not reflect reasoned decision-making.[2022] Similarly, Designated Retail Regulators argue that the Commission failed to provide an analysis of the justness and reasonableness of the local transmission planning processes as a prerequisite to adopting the local transmission planning and right-sizing reforms in Order No. 1920.[2023] Competition Coalition contends that Order No. 1920's findings on encouraging transmission providers to provide their best in-kind replacement estimates and removing other disincentives do not provide a basis for satisfying the first prong of FPA section 206.[2024]

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[2021] Competition Coalition Rehearing Request at 14 (citing *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*)); Industrial Customers Rehearing Request at 4-5; Designated Retail Regulators Rehearing Request at 7, 41.

[2022] Competition Coalition Rehearing Request at 14; Industrial Customers Rehearing Request at 4-5.

[2023] Designated Retail Regulators Rehearing Request at 7.

[2024] Competition Coalition Rehearing Request at 18.

815. Several parties separately assert that the Commission failed to satisfy the first prong of FPA section 206 when it adopted the federal right of first refusal requirement for right-sized replacement transmission facilities.[2025] Competition Coalition contends, and Industrial Customers agree, that Order No. 1920 fails to identify the specific regional transmission planning and cost allocation tariff requirements, particularly those that relate to in-kind replacement processes, that are unjust, unreasonable, or unduly discriminatory or preferential as a result of the lack of an incumbent preference.[2026] Rather, Competition Coalition argues, the identified concern—lack of transparency in local transmission planning as an input to regional transmission planning—has nothing to do with the lack of a right of first refusal in the regional transmission planning process.[2027] Competition Coalition further states that the absence of any nexus between the identified problem in Order No. 1920—that existing regional transmission planning processes are unjust and unreasonable—and the prescribed remedy is glaring as it concerns the federal right of first refusal for right-sized replacement transmission facilities.[2028]

816. Competition Coalition also asserts that Order No. 1920 fails to provide substantial evidence that the existing regional transmission planning framework as it relates to

[2025] *Id.* at 6, 11-19, 36-37; Industrial Customers Rehearing Request at 13-15.

[2026] Competition Coalition Rehearing Request at 12-13; Industrial Customers Rehearing Request at 12-13.

[2027] Competition Coalition Rehearing Request at 13.

[2028] *Id.* at 13.

incumbent public utility preferences for regionally planned, regionally cost allocated projects in existing transmission provider tariff provisions is unjust, unreasonable, or unduly discriminatory or preferential. Competition Coalition also contends that Order No. 1920 does not elaborate on, or support with substantial evidence, the reference to "coordination" in the context of its finding under the first prong of FPA section 206.[2029] Competition Coalition states that substantial evidence is "relevant evidence that a reasonable mind might accept as adequate to support a conclusion."[2030]

**b. Commission Determination**

817. We sustain the finding in Order No. 1920 that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential.[2031] We continue to find that Order No. 1920's reforms to transparency in local transmission planning inputs and coordination between local and regional transmission planning processes are necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.

818. We disagree with Competition Coalition and Advanced Energy that the Commission failed to satisfy the required analysis of FPA section 206 in adopting the reforms to enhance the transparency of local transmission planning inputs and

[2029] *Id.* at 13-14.

[2030] *Id.* at 9.

[2031] Order No. 1920, 187 FERC ¶ 61,068 at P 1569.

coordination between the local and regional transmission planning processes. As the Commission noted in Order No. 1920, reforms to better ensure more consistent implementation of the Order No. 890 transmission planning principles are timely and important in light of the significant investments in transmission infrastructure that now occur through local transmission planning processes.[2032] Further, we continue to find that local and regional transmission planning processes serve essential and complementary roles in ensuring that customers' transmission needs are identified and met at just and reasonable rates, including through the identification, evaluation, and selection of more efficient or cost-effective transmission solutions through regional transmission planning.[2033] As the Commission stated in Order No. 1920, information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning.[2034]

819. The Commission supported its findings in Order No. 1920 with comments and studies in the record highlighting that the lack of transparency and coordination requirements in local transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.[2035] Specifically, the Commission also found that additional coordination between the local

[2032] *Id.* P 1572; *see also id.* P 109.

[2033] *Id.* P 1570.

[2034] *Id.*

[2035] *Id.* P 1571.

and regional transmission planning processes regarding the replacement of aging infrastructure is needed, especially in light of the record evidence that incumbent transmission providers across the country are replacing aging transmission infrastructure as it reaches the end of its useful life[2036] without considering whether a regional transmission solution could be more efficient or cost-effective. Ultimately, the Commission concluded, based on these findings, that the existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes were unjust, unreasonable, and unduly discriminatory or preferential.[2037]

820. We also disagree with arguments raised by Competition Coalition, Industrial Customers, and Designated Retail Regulators that the Commission's findings under FPA section 206 are not supported by substantial evidence and find that Competition Coalition's reliance on *Emera Maine* is misplaced.[2038] Rehearing parties' arguments on this issue ignore the Commission's extensive explanation of the circumstances that have rendered the existing rates and practices affecting those rates unlawful.[2039] The Commission first identified a lack of adequate provisions for transparency and

[2036] *Id.* P 1573, nn.3363-3365.

[2037] *Id.* PP 1573-1574, 1576.

[2038] *See Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017).

[2039] *Id.* PP 1571, 1572.

meaningful input from stakeholders within local transmission planning processes.[2040] In support of this finding, the Commission: (1) cited prior final rules recognizing stakeholders' critical role in effective transmission planning; and (2) found that those prior final rules required reforms to provide for stakeholders' meaningful participation in both local and regional transmission planning processes.[2041]

821. The Commission next identified the lack of a requirement for transmission providers in each transmission planning region to evaluate whether replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs. As noted above, the Commission highlighted evidence from the record that, for example, PJM and NYISO anticipate soon replacing a substantial portion of their aging transmission infrastructure as it reaches the end of its useful life, which will directly affect Commission-jurisdictional rates.[2042] Based on this evidence, the Commission concluded that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes may result in the development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to

[2040] *Id.* P 1571.

[2041] *Id.* P 1571 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152).

[2042] *Id.* P 1573, nn.3363-3365.

customers and render Commission-jurisdictional rates unjust and unreasonable.[2043] We therefore conclude that the Commission found, based on substantial evidence, that these requirements are unjust, unreasonable, or unduly discriminatory, and determined that the identified deficiencies must be addressed to ensure that Commission-jurisdictional rates are just and reasonable.

822. Order No. 1920 also pointed out that the federal right of first refusal for selected right-sized replacement transmission facilities will provide transmission providers with certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility, and this, in turn, will encourage transmission providers to provide their best in-kind replacement estimates.[2044] Accordingly, the Commission found that that a federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning. The Commission added that this will help to ensure that transmission providers identify and select the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs.[2045]

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[2043] *Id.* P 1574.

[2044] *Id.* P 1703; *see infra* Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities section. The Commission defined "in-kind replacement estimates" as "estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years . . . ." Order No. 1920, 187 FERC ¶ 61,068 at P 1677. We clarify that these estimates include, at minimum, identification of the transmission facilities themselves.

[2045] *See infra* Right of First Refusal for Right-Sized Replacement Transmission

823. As Competition Coalition points out in its rehearing request, substantial evidence is "relevant evidence that a reasonable mind might accept as adequate to support a conclusion."[2046] The above discussion makes clear that the Commission examined the relevant data and articulated a rational connection between the facts found and the choices made in enacting the reforms in Order No. 1920. We thus continue to find that the Commission engaged in reasoned decision-making and considered all important aspects of the problem and meaningfully responded to the arguments raised before it.

### 3. Departure from Commission Precedent

#### a. Rehearing Requests

824. Competition Coalition opines that no explanation can be offered for how the right-sizing proposal is not in conflict with FPA section 206 because Order Nos. 1000 and 1000-A required the elimination of federal rights of first refusal.[2047] Competition Coalition also asserts that Order No. 1920 departs from Commission precedent without explanation.[2048]

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Facilities Selected to Meet Long-Term Transmission Needs section.

[2046] Competition Coalition Rehearing Request at 9 (citing *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 94 (3d Cir. 2014)) (citing Mars Home for Youth v. NLRB, 666 F.3d 850, 853 (3rd Cir. 2011).

[2047] Competition Coalition Rehearing Request at 36-37 (citing *S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 71-76).

[2048] *Id.* at 37 n.112, 40.

**b. Commission Determination**

825. We are unpersuaded by Competition Coalition's argument that Order No. 1920 does not provide a reasoned explanation regarding Order No. 1920's departure from Order Nos. 1000 and 1000-A in establishing a federal right of first refusal for right-sized replacement transmission facilities. In Order No. 1920, the Commission recognized that the establishment of a federal right of first refusal for right-sized replacement transmission facilities is an exception to Order No. 1000's general requirement for transmission providers to eliminate any federal right of first refusal for regional transmission facilities selected in a regional transmission plan. The Commission then found that requiring a federal right of first refusal for right-sized replacement transmission facilities aligns with Order No. 1000.[2049] The Commission explained that, in Order No. 1000, transmission providers were required to remove federal rights of first refusal from their OATTs because they undermined the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level, which could lead to unjust and unreasonable rates for Commission-jurisdictional services.[2050] The Commission also explained that, in Order No. 1000, it found that federal rights of first refusal created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level.[2051]

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[2049] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

[2050] *Id.* P 1705; *infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2051] Order No. 1920, 187 FERC ¶ 61,068 at P 1705 (citing Order No. 1000, 136

826. The Commission further explained that Order No. 1000 did not require the elimination of federal rights of first refusal for local transmission facilities, nor did it alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to their own transmission facilities, regardless of whether the upgrade is selected in the regional transmission plan for the purposes of cost allocation.[2052] Because a right-sized replacement transmission facility has the potential to both meet an individual transmission provider's responsibility to maintain the reliability of its existing transmission system and also address a Long-Term Transmission Need more efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility, which includes the need for replacements of existing transmission facilities via local transmission planning processes, the Commission concluded that the reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities.[2053] Specifically, Order No. 1920 found that requiring a federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level. Rather, the Commission found that a federal right of first refusal will promote the consideration of

FERC ¶ 61,051 at P 257).

[2052] *See id.* P 1705 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 319.)

[2053] *Id.* P 1706; *see infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs because it captures both an individual transmission provider's responsibilities and a Long-Term Transmission Need, we believe the right-sizing reform preserves transmission providers' ability to invest in replacements of their own transmission facilities, even if such facilities are right-sized and selected in the regional transmission plan for purposes of cost allocation.[2054] Furthermore, the Commission noted that the reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities because transmission providers may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing their transmission facilities.[2055]

827. We therefore continue to find that providing for a federal right of first refusal for right-sized replacement transmission facilities aligns with the text and stated purpose of Order No. 1000 by ensuring that transmission providers consider more efficient or cost-effective regional transmission solutions.[2056] We also reaffirm that the right-sizing reform does not depart, without explanation, from Commission precedent related to an individual transmission provider's ability to proceed with an in-kind replacement

[2054] *See infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2055] Order No. 1920, 187 FERC ¶ 61,068 at PP 1706-1707; *see infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2056] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

transmission facility. Further, we believe that, without a federal right of first refusal, the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely opt to develop the less efficient or cost-effective in-kind replacement transmission facility rather than a right-sized replacement transmission facility.[2057] Therefore, we continue to find that the establishment of the federal right of first refusal for right-sized replacement transmission facilities that are evaluated and selected as part of Long-Term Regional Transmission Planning is necessary to effectuate this reform and ensure that Commission-jurisdictional rates are just and reasonable.[2058] As the Commission reasoned in Order No. 1920, by establishing a process that requires transmission providers to evaluate opportunities to right-size in-kind replacement transmission facilities to meet transmission needs, the right-sizing reform will encourage transmission providers to provide their best in-kind replacement estimates, as they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. The Commission concluded that together, these reforms will enable transmission providers to ensure that the more efficient or cost-effective regional solution to transmission needs is identified, evaluated, and selected, and therefore that Commission-jurisdictional rates are just and reasonable.

[2057] *See infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section

[2058] Order No. 1920, 187 FERC ¶ 61,068 at PP 1706-1707.

### 4. Commission Authority Under the FPA

#### a. Rehearing Requests

828. Competition Coalition argues that FPA section 206 cannot support the Commission's adoption of a monopoly preference when FPA section 206 mandates the opposite result (prohibition on unduly discriminatory or preferential rates or practices affected rates).[2059] Advanced Energy argues that the FPA lacks a plausible textual basis for the Commission to bestow on the incumbent utilities a "monopoly right" to develop and own certain types of transmission infrastructure.[2060] Thus, Advanced Energy and Competition Coalition assert, the Commission exceeded its authority under FPA section 206.[2061]

829. Both Advanced Energy and Competition Coalition assert that the Commission's application of FPA section 206 is inconsistent with U.S. Supreme Court precedent.[2062] Advanced Energy states that the Commission's reliance on FPA section 206 to bestow a federal right of first refusal raises serious constitutional questions and, therefore, is inconsistent with the constitutional-doubt canon of statutory construction.[2063] Advanced

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[2059] Competition Coalition Rehearing Request at 36.

[2060] Advanced Energy Rehearing Request at 5, 6-7 (citing 16 U.S.C. 824e(a)).

[2061] *Id.* at 5, 8; Competition Coalition Rehearing Request at 22-23.

[2062] Advanced Energy Rehearing Request at 8-10 (citing *West Virginia*, 597 U.S. at 721, 723, 730; *Whitman v. Am. Trucking Ass'ns*, 531 U.S. at 468); Competition Coalition Rehearing Request at 36 (citing *West Virginia*, 597 U.S. at 723).

[2063] Advanced Energy Rehearing Request at 10 (citing Antonin Scalia & Bryan A. Garner, *Reading Law: The Interpretation of Legal Texts* 247-48 (2012) (citing *Crowell v.*

Energy claims that since FPA section 206 contains no explicit language regarding development or ownership of transmission facilities or authorizing the establishment of a federal right of first refusal, relying on FPA section 206 to adopt the right-sizing reform calls into question whether Congress delegated such authority to the Commission and, if so, whether that delegation was proper.[2064]

830. Advanced Energy states that, in enacting FPA section 216, Congress reinforced the FPA's longstanding jurisdictional framework that the Commission does not possess the authority to prevent "any person" from constructing or modifying a transmission facility.[2065] Advanced Energy argues that, as a result, the Commission exceeded its authority under the FPA by granting incumbents a right of first refusal to develop and own right-sized replacement transmission facilities, to the exclusion of all others.[2066] Similarly, Competition Coalition attests that Order No. 1920 failed to demonstrate that the Commission has the legal authority under the FPA to mandate the federal right of first refusal of transmission facilities, and further argues that the FPA provides the

*Benson*, 285 U.S. 22, 62 (1932))).

[2064] *Id.* at 10, 21 (citing *West Virginia*, 597 U.S. 697).

[2065] *Id.* at 8 (citing 16 U.S.C. 824p(g)).

[2066] *Id.* at 5, 8.

Commission no authority to do so.[2067] Undersigned States argue that right-sizing intrudes upon state authority.2068

**b. Commission Determination**

831. We disagree with Advanced Energy's, Competition Coalition's, and Undersigned States' arguments that the reforms in this section, specifically the right-sizing reform and the federal right of first refusal for right-sized replacement transmission facilities, exceed the Commission's authority.[2069] The Commission's authority under FPA section 201 includes "the transmission of electric energy in interstate commerce," and under FPA section 206 the Commission's authority is to ensure that practices affecting Commission-jurisdictional rates are just and reasonable.[2070] As explained in *EPSA*, this jurisdiction extends to practices that "directly affect" such rates.[2071] The federal right of first refusal acknowledges existing precedent recognizing state laws providing an individual transmission provider's ability to proceed with an in-kind replacement transmission facility and encourages transmission providers to provide their best in-kind replacement estimates by preserving the transmission providers' ability to invest in facilities selected

[2067] Competition Coalition Rehearing Request at 7, 21-23.

[2068] Undersigned States Rehearing Request at 36.

[2069] *See* Advanced Energy Rehearing Request at 4-12; Competition Coalition Rehearing Request at 7, 20-40; Undersigned States Rehearing Request at 36.

[2070] *See supra* Federal/State Division of Authority section.

[2071] 577 U.S. at 278.

as right-sized replacement transmission facilities.[2072] The Commission explained that the establishment of a federal right of first refusal in this regard will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address transmission needs.

832. Indeed, rights of first refusal have generally been found to be practices affecting rates, thus confirming that they are within the Commission's jurisdiction—albeit in the context of their removal.[2073] Thus, the Commission's action in Order No. 1920 is entirely consistent with Order No. 1000 in that respect. Advanced Energy and Competition Coalition fail to recognize the inherent contradiction in their arguments. When addressing our statutory authority, the relevant question is whether the Commission can regulate rights of first refusal, not how it chooses to regulate them. The claim that the establishment of a federal right of first refusal for right-sized replacement transmission facilities is beyond the Commission's authority is squarely contrary to Order No. 1000 and *South Carolina*.[2074]

833. We are unpersuaded by arguments that the Commission lacks authority under the FPA to require the right-sizing reform. FPA section 206 provides the Commission with

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[2072] Order No. 1920, 187 FERC ¶ 61,068 at P 1707.

[2073] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 72.

[2074] *Id.* at 73-76 (finding that the Commission was authorized to regulate the right of first refusal provisions in Commission-jurisdictional tariffs and that the Commission correctly concluded that inclusion of rights of first refusal in tariffs and agreements was a "practice affecting a rate triggering the Commission's authority under FPA section 206.").

the authority to determine the just and reasonable rate following a finding that any rate, charge, regulation, or practice is unjust, unreasonable, unduly discriminatory or preferential. The D.C. Circuit has recognized that regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction[2075] and that transmission providers use those processes to "determine which transmission facilities will more efficiently or cost-effectively meet" transmission needs, the development of which directly impacts the rates, terms, and conditions of Commission-jurisdictional service.[2076]

834. We also are unpersuaded by Advanced Energy's and Competition Coalition's claims that the right of first refusal for right-sized replacement transmission facilities requires explicit congressional authorization and find that, notwithstanding references to *West Virginia* in their rehearing requests, the major questions doctrine is not implicated here. As discussed in detail above,[2077] the major questions doctrine is a context-specific analysis that applies only in "extraordinary cases" where an agency action is so extravagant that it is akin to discovering an "elephant in a mousehole."[2078] More specifically, the major questions doctrine comes into play where, despite a "colorable

[2075] Order No. 1920, 187 FERC ¶ 61,068 at P 86 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 at 55-59, 84; *see* Order No. 1000-A, 139 FERC ¶ 61,132 at P 577).

[2076] *Id.* (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56).

[2077] *See supra* Major Questions Doctrine section.

[2078] *See West Virginia*, 597 U.S. at 746.

textual basis" for the agency's claim of authority, the agency action was so extravagant when viewed in light of the statutory context that it was unlikely that Congress would have afforded this claimed authority to the agency, and particularly would not have done so in an oblique or subtle way.[2079]

835. The Advanced Energy and Competition Coalition rehearing requests do not meaningfully engage with the context-specific factors associated with the application of the major questions doctrine. Advanced Energy's theory that the doctrine applies boils down to its characterization of the federal right of first refusal as a "monopoly franchise right" and assertion that replacing transmission projects is extremely expensive.[2080] Competition Coalition similarly relies on a largely conclusory invocation of *West Virginia*, without analysis beyond asserting that this is an "extraordinary case" because the Commission has never previously asserted that Congress granted it this power.[2081]

836. We continue to conclude that the major questions doctrine does not apply to Order No. 1920, which is a rulemaking under the Commission's broad authority over transmission planning processes affecting Commission-jurisdictional rates. Specifically, here, Order No. 1920's inclusion of a federal right of first refusal for right-sized replacement transmission facilities falls well within the Commission's authority under FPA section 206 over "practice[s] . . . affecting" rates, the same grant of statutory

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[2079] *Id.* at 722-23.

[2080] Advanced Energy Rehearing Request at 9-10

[2081] Competition Coalition Rehearing Request at 34, 36.

authority supporting issuance of Order No. 1920.[2082] As a result, for all the reasons that we find that the major questions doctrine is inapplicable to Order No. 1920 as a whole,[2083] we likewise find that Advanced Energy and Competition Coalition have not shown that the major questions doctrine applies to Order No. 1920's inclusion of a federal right of first refusal for right-sized replacement transmission facilities.

837. We are also unpersuaded by Advanced Energy's claims that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities raises constitutional questions and is therefore inconsistent with the constitutional-doubt canon of statutory construction.[2084] Advanced Energy does not discuss the substance of this doctrine, cite any authority that relates to this doctrine, or explain how—by authorizing the Commission to regulate practices affecting rates, which includes the local transparency improvements and the right-sizing reform—Congress would have impermissibly delegated legislative power to the Commission.[2085]

838. We also disagree with Advanced Energy that the Commission exceeded its authority under FPA section 216 and find such arguments to be misplaced. FPA section

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[2082] *See EPSA*, 577 U.S. at 277-78; *S.C. Pub. Serv. Auth. v. FERC*, 762 at 56-57; *CAISO*, 372 F.3d at 399-404.

[2083] *See supra* Major Questions Doctrine section.

[2084] *See* Advanced Energy Rehearing Request at 10 (citing Antonin Scalia & Bryan A. Garner, *Reading Law: The Interpretation of Legal Texts*, at 247-48 (2012) (citing *Crowell v. Benson,* 285 U.S. at 62)).

[2085] *Id.*; *see also supra* Major Questions Doctrine section

216 governs the Commission's authority with respect to authorization of a construction permit for a transmission facility located within a National Interest Electric Transmission Corridor under certain circumstances. FPA section 216 does not alter or restrict the Commission's authority to identify a replacement rate under section 206 of the FPA, including the provision for or the removal of a federal right of first refusal, to ensure transmission providers' OATTs are just and reasonable and not unduly discriminatory or preferential. The federal right of first refusal for right-sized replacement transmission facilities is not aimed at, nor does it directly regulate, an area of state authority.[2086] As discussed in Order No. 1920 and above, the Commission is not unlawfully supplanting state authority, including siting and development processes.[2087] States retain their authority over those processes and the federal right of first refusal for right-sized replacement transmission facilities is not directed at those practices nor does it divest states of their authority. As explained above, the right-sizing processes, including the right of first refusal for right-sized replacement transmission facilities, are directed at Commission-jurisdictional transmission planning processes.

[2086] *See supra* Federal/State Division of Authority section (explaining that Commission regulations are not unlawful even if they substantially affect areas of reserved state jurisdiction so long as the Commission is directly regulating within its areas of authority under the FPA, rather than attempting to directly regulate within state jurisdiction).

[2087] *See supra* Federal/State Division of Authority section; *See also* Order No. 1920, 187 FERC ¶ 61,068 at P 271.

839. We are not persuaded by Advanced Energy's acontextual reading of FPA section 216(g) which posits that—in providing backstop siting authority to the Commission under FPA section 216 and allowing the Commission, in certain circumstances, to grant construction permits for transmission facilities within designated National-Interest Electric Transmission Corridors—Congress was subtly intending to negate the Commission's authority in FPA sections 205 or 206, particularly with respect to the right-sizing rights of first refusal or rights of first refusal more generally. The far more natural interpretation of this provision is that it means what it says, clarifying the impact of "this section" of the FPA: that despite creating such backstop permitting authority residing with the Commission, FPA section 216 does not preclude the construction or modification of transmission facilities in accordance with state law.[2088]

### 5. Policy Against Anticompetitive Practices

#### a. Rehearing Requests

840. Both Competition Coalition and Advanced Energy claim that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities is inconsistent with federal policy against anticompetitive practices.[2089] Specifically, Advanced Energy asserts that the federal right of first refusal is inconsistent

[2088] We note, further, that Order No. 1920 is not a regulation under FPA section 216 and no part of the right-sizing right of first refusal relies on Commission authority under FPA section 216.

[2089] Competition Coalition Rehearing Request at 67-68 (citing Exec. Order No. 14,036, 3 CFR 100.1); Advanced Energy Rehearing Request at 10-11.

with Supreme Court finding that "the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[2090] Competition Coalition contends that the reform is contrary to appellate courts' affirmation that monopoly preferences are against the public interest.

**b. Commission Determination**

841. Order No. 1920's conclusion that the federal right of first refusal for right-sized replacement transmission facilities is within the Commission's authority is further supported by the history and context of the FPA broadly, and rights of first refusal generally—contrary to the arguments in the rehearing requests. As the Supreme Court has recognized, electric utilities have historically been vertically integrated monopolies, including as to transmission.[2091]

842. When Congress enacted the FPA, it charged the Commission with ensuring that rates and practices were "just and reasonable" and not unduly discriminatory or preferential. Within these parameters, the statutory text does not require a particular approach. Thus, Advanced Energy's and Competition Coalition's invocation of a policy

[2090] Advanced Energy Rehearing Request at 10-11 (citing *Otter Tail v. U.S.*, 410 U.S. 366, 374 (1973)).

[2091] *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash.*, 554 U.S. 527, 535–36 (2008) (finding that, historically, electric utilities have been monopolies).

against anticompetitive practices is unpersuasive.[2092] The Commission's authority is defined and delineated by the FPA, not by reference to a general policy that may favor competition. Notably, the case Advanced Energy cites in this context, *Otter Tail*, did not address the Commission's authority under FPA section 205 or 206, and instead considered whether provisions of the FPA implicitly repealed otherwise applicable antitrust laws.[2093]

### 6. Other Arguments

#### a. Rehearing Requests

843. Competition Coalition asserts that Order No. 1920 fails to meaningfully engage with NOPR arguments and rebut arguments presented in those comments. Competition Coalition also asserts that the phrase federal rights of first refusal is a "made-up phrase" that has no history in the FPA.[2094] Competition Coalition adds that the federal right of first refusal for right-sized replacement transmission facilities is likely to encourage gaming.[2095]

#### b. Commission Determination

844. We also find that Competition Coalition's remaining arguments are unpersuasive as they fail to engage with the statutory text or context and, ultimately, have little to do

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[2092] Advanced Energy Rehearing Request at 10-11.

[2093] *See id.* at 10 n.30.

[2094] Competition Coalition Rehearing Request at 24-29.

[2095] *Id.* at 61, 68-71.

with the Commission's statutory authority, notwithstanding how they are categorized in Competition Coalition's rehearing request.

845. A large swath of Competition Coalition's arguments discuss the history of the phrase "federal right of first refusal," arguing that "the phrase was nothing more than a made-up general reference for clauses in [Commission]-jurisdictional contracts or tariffs implemented by existing transmission owners to impede independent transmission developers seeking to develop cost-of-service transmission."[2096] We find that this discussion has little bearing on the issue of the Commission's authority, which is defined by the statutory text and relevant precedent construing this text. As discussed above, we find that establishing the federal right of first refusal for right-sized replacement transmission facilities is within our authority and consistent with that history. We also note that Order No. 1000 did not require the removal of all rights of first refusal. Thus, Order No.1000 does not suggest that establishment of a federal right of first refusal for right-sized replacement transmission facilities is beyond the Commission's authority.

846. We also find that most of Competition Coalition's other arguments—although housed in a portion of their request for rehearing contending that Order No. 1920 exceeds the Commission's statutory authority—are mislabeled. On their substance, these arguments amount to disputes over whether the federal right of first refusal for right-sized replacement transmission facilities is just and reasonable and not unduly discriminatory

[2096] *Id.* at 24-29 (arguing that such provisions were not based on requirements of the FPA or rights inherent in the FPA).

or preferential and whether the Commission departed from its precedent without adequate explanation, albeit peppered with assertions that the federal right of first refusal for right-sized replacement transmission facilities is not supported by the FPA.[2097] Throughout this order, we affirm that the replacement rate set by the Commission in Order No. 1920 is just and reasonable and not unduly discriminatory.[2098] We find that the Commission's authority is plainly stated in FPA section 206 to evaluate rates and practices to determine whether they are unjust and unreasonable or unduly discriminatory or preferential, and, if so, prescribe a replacement rate that is just and reasonable and not unduly discriminatory or preferential. On its face, the federal right of first refusal for right-sized replacement transmission facilities is an exercise of that authority, as discussed above.

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[2097] *See id.* at 32-40 (arguing that Order No. 1920 departs from the approach of previous Commission orders seeking to curtail transmission provider self-interest and challenging the Commission's rationale for adopting the federal right of first refusal for right-sized replacement transmission facilities); *id.* at 35-36 (arguing that the rationale of *Orangeburg, S.C. v.* FERC, 862 F.3d 1071 (2017), and the Commission's findings in Order No. 1000, require the elimination of disparate treatment of nonincumbent transmission providers); *id.* at 36-40 (arguing that FPA section 206 requires "elimination of preferential rates or practices affecting rates" and that the federal right of first refusal for right-sized replacement transmission facilities is inconsistent with this requirement, that the Commission cannot "ignore its prior declaration that rights of first refusal are unduly discriminatory or preferential," and that Order No. 1920 is disingenuous in distinguishing precedent or claiming that it is not creating a "new preference"); *cf. id.* at 29-32 (discussing Order Nos. 1000 and 1000-A, arguing that because the Commission rejected "monopoly preference provisions" in those orders, even applying a heightened contract review, there is "no support for an assumption that the Commission enjoys Congressionally granted authority to simply create a federally sanctioned 'cartel-like' monopoly preference").

[2098] *See supra* The Commission Demonstrated that the Replacement Rate is Just and Reasonable section.

### B. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process

#### 1. Order No. 1920

847. In Order No. 1920, the Commission required transmission providers to revise the regional transmission planning process in their OATTs to enhance the transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through the local transmission planning process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[2099] Specifically, the Commission required that the regional transmission planning process include at least three publicly noticed stakeholder meetings per regional transmission planning cycle concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.[2100] The Commission stated that the requirement to establish this process ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process.[2101] The Commission also clarified that these requirements applied only to local transmission

[2099] Order No. 1920, 187 FERC ¶ 61,068 at P 1625.

[2100] *Id.* P 1626.

[2101] *Id.*

planning that is within the scope of Order No. 890 and is therefore already subject to Order No. 890 transparency requirements. As such, the Commission stated, this requirement does not apply to asset management projects.[2102]

848. The Commission required that prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting).[2103] Furthermore, the Commission required that no fewer than 25 calendar days after the Assumptions Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting).[2104] Finally, the Commission required that, no fewer than 25 calendar days after the Needs Meeting, transmission providers in each transmission planning region must convene, collectively,

[2102] *Id.* P 1625 (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160, at PP 30-40 (2018); *Cal. Pub. Utils. Comm'n v. Pac. Gas. & Elec. Co.*, 164 FERC ¶ 61,161, at PP 65-74 (2018) (finding that Order No. 890's local transmission planning requirements do not apply to asset management projects that do not increase capacity or do so incidentally)).

[2103] *Id.* P 1627.

[2104] *Id.*

as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting).[2105]

849. Additionally, the Commission required that the materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.[2106] Specifically, the Commission required transmission providers to publicly post the meeting materials no fewer than five calendar days prior to each of the three publicly noticed stakeholder meetings to allow time for stakeholders to review materials in advance of each meeting.[2107] The Commission also required that transmission providers allow for a period of no fewer than 25 calendar days following the Solutions Meeting to review and consider stakeholder feedback on the local transmission solutions identified to meet the local transmission needs before the local transmission plan can be incorporated in the transmission planning region's planning models.[2108] Lastly, the Commission required that transmission providers must respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate in these three required stakeholder meetings.[2109]

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[2105] *Id.*

[2106] *Id.*

[2107] *Id.* P 1628.

[2108] *Id.*

[2109] *Id.*

850. In Order No. 1920, the Commission declined to adopt alternatives requested by commenters to this set of reforms because such proposals were not included in the NOPR and, as a result, the requests were beyond the scope of the proceeding.[2110] The Commission noted, however, that several of these issues may be examined in the Commission's ongoing Transmission Planning and Cost Management proceeding.[2111]

### 2. Requests for Additional Reforms

#### a. Requests for Rehearing and Clarification

851. Several parties request rehearing of the Commission's decision to exclude asset management projects from the local transmission planning transparency requirements in the final rule.[2112] Old Dominion states that the Commission failed to address the lack of meaningful transparency in local transmission planning by deciding to exclude asset management projects from the local transmission planning transparency requirements, which it argues is an error that will perpetuate unjust and unreasonable rates.[2113] Further, Old Dominion contends that the Commission's assertion that there is not sufficient record evidence or that it would be outside the scope of the proceeding to adopt reforms that were not proposed in the NOPR is unreasonable and inconsistent with other aspects of the

[2110] *Id.* P 1648.

[2111] Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22-8-000 (Apr. 21, 2022).

[2112] NESCOE Rehearing Request at 26-31; Ohio Commission Federal Advocate Rehearing Request at 21-24; Old Dominion Rehearing Request at 4, 5-9.

[2113] Old Dominion Rehearing Request at 5, 9.

final rule where the Commission adopted proposals that were neither supported by sufficient record evidence nor included in the NOPR.[2114] Old Dominion states that if the Commission does not grant rehearing on this issue, then the Commission should undertake further reforms for local transmission planning, such as in Docket No. AD22-8-000.[2115]

852. NESCOE states that the Commission's decision to exclude asset management projects[2116] from the scope of the local transmission planning transparency enhancements does not constitute reasoned decision-making, because the final rule does not sufficiently address concerns that asset condition projects are not subject to sufficient transparency, scrutiny, and review requirements.[2117] NESCOE further argues that, despite the Commission's acknowledgement that reforms are needed to ensure regional transmission planning and cost allocation are just and reasonable, the Commission's failure to adopt such reforms based on a single-sentence rationale demonstrates that the Commission has not "made a reasoned decision based upon substantial evidence in the record," nor has it "articulate[d] a satisfactory explanation for its action including a rational connection

[2114] *Id.* at 5-6, 8 (contending that Order No. 1920 prohibits different cost allocation methods for economic, reliability, and public policy requirements, which the Commission did not propose in the NOPR).

[2115] *Id.* at 9.

[2116] NESCOE notes that these in-kind replacement projects are known as asset condition projects in New England. NESCOE Rehearing Request at 6.

[2117] *Id.* at 26-33, 34.

between the facts found and the choice made."[2118] NESCOE argues that the exemption of asset management projects from the local transmission planning transparency requirements results in a regulatory gap where transmission costs are unreviewed at both the state and federal level.[2119] NESCOE contends that this is a particularly acute concern in New England where, since February 2023, transmission owners have brought $3.3 billion in asset management projects through ISO-NE's Planning Advisory Committee.[2120]

853. Ohio Commission Federal Advocate argues that the Commission's adoption of "perfunctory" transparency reforms for local planning processes was arbitrary and capricious, and will do nothing to close the regulatory gap or provide oversight for local projects.[2121] Ohio Commission Federal Advocate notes that given the increasing portion of transmission facilities that are considered "supplemental projects"[2122] in PJM, the reforms adopted in Order No. 1920 do little to shift the scales and the reforms may increase the portion of the transmission system built through a local transmission planning process.[2123] As such, Ohio Commission Federal Advocate contends that the

[2118] *Id.* at 30-31 (citing *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th at 800).

[2119] *Id.* at 29.

[2120] *Id.* at 28.

[2121] Ohio Commission Federal Advocate Rehearing Request at 21-22.

[2122] In PJM, "supplemental projects" is the term used for local projects. *Id.* at 23.

[2123] *Id.*at 23-24.

Commission neglected its duty under the FPA to ensure just and reasonable rates by imposing reforms that will not curb rising transmission costs or result in holistic transmission planning.[2124]

854. Industrial Customers request rehearing and argue the Commission failed to engage requests that call for implementation of an independent transmission monitor. Given the increase in spending on transmission projects, Industrial Customers argue that clarifying or expanding existing independent market monitor functions or creating an independent transmission monitor would be a timely and appropriate exercise of the Commission's authority to remedy unjust and unreasonable rates.[2125] Moreover, Industrial Customers contend that Order No. 1920 falls short of ensuring just and reasonable rates because it does not undertake reforms of transmission formula rates or the Commission's prudence standard.[2126] Industrial Customers argue that since Order No. 1920 failed to implement any concrete reforms to protect consumers, rehearing is warranted.[2127]

855. PIOs request rehearing arguing that the Commission has sidestepped evidence that they and other parties offered when the Commission concluded that certain suggestions regarding the local transmission planning process were outside the scope of the

[2124] *Id.* at 21, 23.

[2125] Industrial Customers Rehearing Request at 29-31.

[2126] *Id.* at 33-34.

[2127] *Id.* at 38.

proceeding.[2128] PIOs argue that while Order No. 1920's reforms take some steps in the right direction, Order No. 1920 does not actually require the kind of comprehensive information transparency, scenario-based planning, multi-benefit analysis, and process coordination necessary for stakeholders to verify whether local transmission projects are prudent or whether a regional solution is more appropriate.[2129] PIOs argue that the Commission must require transmission providers to meet their burden under FPA section 205(e) to prove that their local transmission projects are the least-cost way to meet the needs of the transmission system. PIOs further argue the Commission should grant rehearing to ensure that utilities only construct local transmission projects when they are the best option for maintaining reliability and at least cost to consumers.[2130]

**b. Commission Determination**

856. We sustain the determination in Order No. 1920 to exclude asset management projects from the information on local transmission planning inputs that transmission providers must include for stakeholder review as part of the Assumptions, Needs, and Solutions Meetings. We reiterate that planning for asset management projects, which do not increase transmission capacity or only do so incidentally, is not required to be included within the scope of local transmission planning that is subject to Order No. 890

[2128] PIOs Rehearing Request at 50.

[2129] *Id.* at 51-52.

[2130] *Id.* at 53-54 (citing *Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162, 178 (D.C. Cir. 2022)) (other citations omitted).

transparency requirements,[2131] and as such, it was reasonable for the Commission to exclude them from the requirements in Order No. 1920.[2132] Moreover, the Commission did not propose in the NOPR to require transmission providers to include information related to asset management projects in the information that they provide as part of the Assumptions, Needs, and Solutions Meetings. Instead, to enhance stakeholders' visibility into local transmission planning inputs as they are integrated into the regional transmission planning process, the Commission proposed in the NOPR – and adopted in the final rule – requirements to enhance the transparency of such inputs, which are already subject to the local transmission planning transparency requirements of Order No. 890, in the regional transmission planning process.[2133] We continue to expect these

[2131] Order No. 1920, 187 FERC ¶ 1625 (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at PP 30-40; *Cal. Pub. Utils. Comm'n v. Pac. Gas. & Elec. Co.*, 164 FERC ¶ 61,161 at PP 65-74 (finding that Order No. 890's local transmission planning requirements do not apply to asset management projects that do not increase capacity or do so incidentally)).

[2132] *Id.* P 1625.

[2133] NOPR, 179 FERC ¶ 61,028 at P 398 (identifying the need for reform based in part on a finding that "implementation of [the Order No. 890 local transmission planning principles] in local transmission planning processes appears to remain uneven", and that "reforms to better ensure more consistent implementation of these principles may be timely"); *id*. P 400 (proposing to require transmission providers to revise their OATTs "to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs."); *id.* P 402 (stating that "requirements are needed to ensure just and reasonable Commission-jurisdictional rates because the information provided will better facilitate the identification of regional transmission facilities"); Order No. 1920, 187 FERC ¶ 61,068 at P 1625 (clarifying that the requirement "applies only to local transmission planning that is within the scope of Order No. 890 and is therefore already subject to Order No. 890 transparency

reforms to enhance the transparency between the local and regional transmission planning processes, which will help reduce the possibility that transmission providers will develop local transmission facilities without adequately considering whether there is a more efficient or cost-effective regional transmission solution that could address their local transmission needs.[2134] That said, we note that nothing in Order No. 1920 prevents transmission providers from choosing to apply Order No. 1920's requirements to enhance the transparency of local transmission planning inputs to asset management projects.

857. We disagree with parties that request rehearing on the grounds that the Commission's decision-making was arbitrary and capricious or failed to consider the record evidence. Further, we disagree with Ohio Commission Federal Advocate that the Commission neglected its duty under the FPA to ensure just and reasonable rates. We continue to find, as we found in Order No. 1920, that the enhanced transparency requirements are specifically designed to provide needed transparency to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[2135] As such, we find that the scope of the relevant reforms required by Order No. 1920 is sufficient to remedy the deficiencies in local transmission planning that the

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requirements" and does not apply to asset management projects)).

[2134] Order No. 1920, 187 FERC ¶ 61,068 at P 1629.

[2135] *Id.* P 1632.

Commission set out to resolve in Order No. 1920, even if some parties would have preferred that the Commission had gone further.[2136]

858. For similar reasons, we are unpersuaded by Industrial Customers' and PIOs' requests for additional reforms to transmission planning processes generally. The proposals raised by these parties in their rehearing requests were not included in either the NOPR or Order No. 1920 and, as noted above, we find that the relevant reforms required pursuant to Order No. 1920 are sufficient to remedy the problem that Order No. 1920 set out to solve.[2137] The Commission will continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future.[2138]

### 3. Stakeholder Meeting Clarifications

#### a. Request for Rehearing and Clarification

859. SERTP Sponsors request clarification that the standard for evaluating transmission providers' obligation to respond to stakeholder feedback is consistent with Order No. 890 and applies equally to local, regional, and Long-Term Regional Transmission

[2136] *See New York v. FERC*, 531 U.S. at 26-27 (affirming that the Commission did not have an obligation extend its open access remedy to bundled retail transmissions because the remedy it ordered constituted a sufficient response to the problems the Commission had identified in the wholesale market).

[2137] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1648, 1737.

[2138] We note, for example, the ongoing proceeding in Docket No. AD22-8-000 on Transmission Planning and Cost Management.

Planning.[2139] Specifically, SERTP Sponsors assert that further clarification is necessary with respect to the Commission's statement that transmission providers are encouraged "to be as responsive as possible to stakeholder comments and questions" because this statement could be read to go beyond standards previously established in Order No. 890 and expand transmission providers' obligation to respond beyond what is necessary to support meaningful participation in stakeholder meetings.[2140] Thus, SERTP Sponsors request that the Commission clarify that transmission providers are not obligated to incorporate stakeholder proposals or comments into their transmission plans and that the ultimate transmission planning responsibility is with the transmission provider.[2141]

860. Regarding the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, SERTP Sponsors also request that the Commission clarify that these meetings of different transmission providers do not need to be held as one. SERTP Sponsors explain that their transmission planning region consists of multiple transmission providers over a 12-state footprint, and they contend that the Commission should clarify that this requirement can be satisfied by a single transmission provider holding separate meetings that include its own Assumptions, Needs, and Solutions Meetings.[2142] SERTP

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[2139] SERTP Sponsors Rehearing Request at 23-24.

[2140] *Id.* at 24 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1645) (emphasis omitted).

[2141] *Id.*

[2142] *Id.* at 24-25.

Sponsors assert that, in the event that the Commission does not so clarify, the requirements for the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting may become unduly burdensome and inconsistent with Order No. 1920's requirement, which is based on the model used by PJM's transmission owners to hold separate meetings for different local transmission owners' local plans.[2143] SERTP Sponsors argue that holding "collective" Assumptions, Needs, and Solutions Meetings is unnecessary to achieve the Commission's transparency objections, and further contends that requiring so would be an unexplained departure from the PJM precedent and otherwise arbitrary and capricious.[2144]

### b. Commission Determination

861. We clarify, in response to SERTP Sponsors' request, that transmission providers are not obligated to incorporate stakeholder proposals or comments resulting from the stakeholder meeting process into their transmission plans, and we agree with SERTP Sponsors that the ultimate transmission planning responsibility remains with the transmission provider.[2145] In encouraging transmission providers to be as responsive as possible to stakeholder comments and questions as part of the stakeholder meeting process, the Commission in Order No. 1920 did not establish new requirements for transmission providers that did not previously apply; rather, the description of the

[2143] *Id.* at 25.

[2144] *Id.* at 25 (citations omitted).

[2145] *Id.* at 24.

requirement that transmission providers respond to questions or comments in a manner that allows stakeholders to meaningfully participate in the stakeholder meetings explains existing requirements established under Order No. 890 and that apply to local transmission planning processes, existing Order No. 1000 regional transmission planning processes, and Long-Term Regional Transmission Planning processes.[2146]

862. In response to SERTP Sponsors' request that the Commission clarify that the stakeholder meetings of the different transmission providers do not need to be held collectively as a single meeting,[2147] we agree and clarify that, provided that the transmission provider meets the requirements of Order No. 1920 with respect to public notices and opportunities for stakeholders to submit comments before and after each meeting, transmission providers need not hold a single stakeholder meeting among all transmission providers in a transmission planning region. We recognize that transmission planning regions often cover significant geographic range and are comprised of many diffuse transmission providers, such that imposing a requirement that each stakeholder meeting includes all transmission providers and stakeholders may create undue burden

[2146] *See* Order No. 890, 118 FERC ¶ 61,119 at P 452 ("Transmission providers are, however, required to craft a process that allows for a reasonable and meaningful opportunity to meet or otherwise interact meaningfully."); *id*. P 454 ("This means that customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input."); *id*. P 488 ("The transmission planning required by this Final Rule is intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers.").

[2147] SERTP Sponsors Rehearing Request at 25.

and impede meaningful participation. Instead, transmission providers may hold separate Assumptions Meetings, Needs Meetings, and Solutions Meetings for individual transmission providers within a transmission planning region, provided that the process ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning information throughout the regional transmission planning process and otherwise meets all the Order No. 1920 requirements described above.

### C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

#### 1. Eligibility

##### a. Order No. 1920

863. In Order No. 1920, the Commission required transmission providers, as part of each Long-Term Regional Transmission Planning cycle, to evaluate whether transmission facilities (1) operating above a specified kV threshold and (2) that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years, can be "right-sized" to more efficiently or cost-effectively address a Long-Term Transmission Need.[2148] The Commission also required that each transmission provider submit its in-kind replacement estimates (i.e., estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facilities

[2148] Order No. 1920, 187 FERC ¶ 61,068 at P 1677.

anticipates replacing in-kind with a new transmission facility during the next 10 years) for use in Long-Term Regional Transmission Planning sufficiently early in each Long-Term Regional Transmission Planning cycle.[2149]

864. The Commission further adopted the NOPR proposal to define "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[2150] The Commission clarified that, for the purposes of the right-sizing reform, an "in-kind replacement transmission facility" is a new transmission facility that: (1) would replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as needing to be replaced; (2) would result in no more than an incidental increase in capacity over the existing transmission facility identified as needing to be replaced; and (3) is located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility identified as needing to be replaced.[2151]

865. Similarly, the Commission also clarified that, for the purposes of the right-sizing reform, a "right-sized replacement transmission facility" is a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a

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[2149] *Id.*

[2150] *Id.* P 1678 & n.3580.

[2151] *Id.* P 1678.

Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate.[2152]

866. In Order No. 1920, the Commission also required transmission providers to establish a multi-step process in their OATTs that provides for the implementation of the right-sizing reform. Specifically, the Commission required that transmission providers in each transmission planning region must propose a point sufficiently early in each Long-Term Regional Transmission Planning cycle at which each individual transmission provider in the transmission planning region will submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning.[2153] Next, the Commission required that, if transmission providers identify a right-sized replacement transmission facility as a potential solution to a Long-Term Transmission Need as part of Long-Term Regional Transmission Planning, that right-sized replacement transmission facility must be evaluated in the same manner as any other proposed Long-Term Regional Transmission Facility to determine whether it is the more efficient or cost-effective

[2152] *Id.* P 1679.

[2153] *Id.* P 1681.

transmission facility to address the transmission need.[2154] The Commission clarified that it is at this stage that transmission providers must use the in-kind replacement estimates to determine if in-kind replacement transmission facilities could be right-sized to more efficiently or cost-effectively address a Long-Term Transmission Need(s).[2155] Finally, the Commission required that, if a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution, then the right-sized replacement transmission facility must be considered for selection.[2156]

867. The Commission further required that, for the purposes of implementing the right-sizing reform, transmission providers must propose on compliance a threshold that does not exceed 200 kV to be used in identifying transmission facilities that an individual transmission provider anticipates replacing in-kind with a new transmission facility during the next 10 years, which it must then include in its in-kind replacement estimates.[2157] The Commission clarified that the 10-year timeframe for in-kind replacement estimates should reflect a transmission provider's estimates of the

[2154] *Id.*

[2155] *Id.*

[2156] *Id.* As explained in the Right of First Refusal section below, the Commission required the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs. *Id.* P 1702.

[2157] *Id.* PP 1677, 1683 & n.3584.

transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle.[2158]

**b. Requests for Rehearing and Clarification**

868. In its rehearing request, Advanced Energy argues that the term "right-sized replacement facility" is too vague.[2159] Competition Coalition argues that the definition of the term ignores Order No. 1000-A because the Commission has already determined in Order No. 1000-A that the replacement of an entire transmission facility is an entirely new transmission facility.[2160] Competition Coalition notes that, in Order No. 1000-A, the Commission addressed the issue of granting a preference for an incumbent transmission owner to build a transmission project for upgrades and not an entirely new transmission facility, determining that an upgrade involves the replacement of only part of an existing facility.[2161] Competition Coalition argues that since Order No. 1920 fails to acknowledge the justification for the Commission's departure from existing Commission precedent that

[2158] *Id.* at P 1685.

[2159] Advanced Energy Rehearing Request at 14-15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678).

[2160] Competition Coalition Rehearing Request at 51-57 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 426; *NYISO*, 151 FERC ¶ 61,040 at P 96 (additional citation omitted)).

[2161] Competition Coalition at 51-52 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 426).

limits retention of a preference only for a regional transmission project that represents a replacement of part of an existing transmission facility and not the replacement of an entire transmission facility, Order No. 1920 is arbitrary and capricious.[2162]

869. Similarly, some petitioners argue that Order No. 1920's findings regarding rights-of-way are flawed or inconsistent with Commission precedent.[2163] For example, Advanced Energy highlights that language regarding the "same general route as, and/or use [] the existing rights-of-way of, the existing transmission facility identified as needing to be replaced" could require anything from zero land acquisition cost (if the facility is entirely within a wholly owned right-of-way) to millions of dollars (if the facility is entirely outside of an existing right-of-way but follows the same general route).[2164] Advanced Energy argues that, given such vagueness, to have the chance of passing muster under the APA, the Commission should remove this ambiguity by limiting any right of first refusal to a right-sized replacement facility that is entirely within existing, permanent rights-of-way.[2165] NESCOE similarly argues that the final rule's lack of a definition of "general route" or discussion of why it is appropriate to use a

[2162] *Id.* at 52.

[2163] Advanced Energy Rehearing Request at 14-15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678); Competition Coalition Rehearing Request at 57-59 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678; *MISO*, 147 FERC ¶ 61,127 at P 244; *NYISO*, 151 FERC ¶ 61,040 at P 96).

[2164] Advanced Energy Rehearing Request at 14 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678).

[2165] *Id.* at 14-15.

vague term in place of the well-established "rights-of-way" necessitates the Commission to act to fulfill its statutory duty under the FPA and that, as written, the right-sizing reform could be interpreted to the detriment of consumers.[2166]

870. Competition Coalition argues that the Commission's right-sizing reform contravenes existing Commission precedent regarding the use of rights-of-way, noting that, under Order No. 1000-A, the Commission found that the use of an existing right-of-way is not determinative of whether the facility is a new transmission facility but rather the relevant issue was "whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities."[2167] Competition Coalition further points to Commission rejection of a proposal from MISO to give preference to transmission owners for facilities built on the existing rights-of-way since the Commission determined that issues surrounding rights-of-way is an issue for the authority granting the rights-of-way.[2168]

871. Competition Coalition argues that the OATT language associated with the right-sizing reform is ambiguous, unworkable, and will cause confusion and litigation.[2169] Competition Coalition highlights the terms "anticipates," "right-sizing," "as discussed in

[2166] NESCOE Rehearing Request at 32-33.

[2167] Competition Coalition Rehearing Request at 57-58 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 427).

[2168] *Id.* (citing *MISO*, 147 FERC ¶ 61,127 at P 244).

[2169] *Id.* at 72.

Order No. 1920," "not to exceed 200 kV," "more efficiently," and "cost-effectively" as being undefined in the final rule.[2170] Competition Coalition also contends that the absence of OATT language that gives an independent entity the responsibility to carry out and administer right-sizing opportunities or monitor against potential planning abuses confirms the need for an independent transmission system planner or monitor.2171

872. In its rehearing request, Dominion requests clarification of the proposed 200 kV threshold for determining whether a transmission facility is eligible for right-sizing.[2172] Specifically, Dominion explains that while the Commission refers to a "maximum threshold," Dominion seeks clarification that the use of the word "maximum" does not foreclose evaluation of projects above and below that threshold. Dominion explains that, in simpler terms, transmission providers must consider for right-sizing purposes all transmission facilities with projected in-kind replacements currently operating at or above 200 kV, but they may propose a lower threshold on compliance.[2173]

### c. Commission Determination

873. We sustain our findings in response to Advanced Energy's, Competition Coalition's, and NESCOE's rehearing requests pertaining to the term "right-sized replacement facility." As the Commission explained in Order No. 1920, the right-sizing

[2170] *Id.* at 73-74.

[2171] *Id.* at 74.

[2172] Dominion Rehearing Request at 35.

[2173] *Id.* at 35-36.

reform was adopted, as modified from the NOPR proposal, with additional requirements to ensure that the use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.[2174] As highlighted in Order No. 1920, a right-sized replacement transmission facility would replace the existing transmission facility that the transmission provider included in its in-kind replacement estimate, and extends to any portion of the right-sized replacement facility located within a given transmission provider's retail distribution service territory or footprint.[2175] The Commission found that a right-sized replacement transmission facility has the potential to both meet an individual transmission provider's responsibility to maintain the reliability of its existing transmission system and address a Long-Term Transmission Need more efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility.[2176]

874. In response to Competition Coalition's argument that Order No. 1920 is inconsistent with Order No. 1000-A, which specified that upgrades do not include entirely new transmission facilities, we note that the Commission is entitled to change its approach and depart from prior precedent, provided that it acknowledges the change in policy and provides a reasoned explanation for the new approach.[2177] We acknowledge

[2174] *Id.* P 1679.

[2175] *Id.* P 1702.

[2176] *Id.* P 1682.

[2177] *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 515-516; *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 784 (1968); *see also State Farm*, 463 U.S. at 42

that in Order No. 1920, the Commission, with explanation, departed from its precedent in Order No. 1000-A, as well as in *MISO* and *NYISO*.[2178] In Order No. 1920, the Commission explicitly recognized that "the establishment of a federal right of first refusal for right-sized replacement transmission facilities is an exception to Order No. 1000's general requirement for transmission providers to eliminate any federal right of first refusal for regional transmission facilities selected in a regional transmission plan."[2179] However, the Commission found that the Commission's reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities.[2180] The Commission then explained at length why this is the case,

("[W]e fully recognize that regulatory agencies do not establish rules of conduct to last forever.") (internal quotations omitted); *Greater Bos. Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C. Cir. 1970) (an agency may change its course as long as it "suppl[ies] a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored."), *cert. denied*, 403 U.S. 923 (1971).

[2178] *See MISO*, 147 FERC ¶ 61,127 at P 238; *NYISO*, 151 FERC ¶ 61,040 at P 96. In Order No. 1000-A, the Commission clarified that "the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility." Order No. 1000-A, 139 FERC ¶ 61,132 at P 426.

[2179] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

[2180] *Id.* P 1706; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 1705 (explaining that Order No. 1000 required transmission providers to remove federal rights of first refusal from their OATTs because they undermined the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level and created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions at the regional level) (citations omitted).

satisfying the Commission's obligation to provide a reasoned explanation for its new policy.

875. Specifically, the Commission found that requiring a federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions at the regional level; instead, it will *promote* the consideration of potential regional transmission solutions to address Long-Term Transmission Needs.[2181] When compared against the alternative of piecemeal development of in-kind replacement facilities, the right-sizing reform ensures that Long-Term Regional Transmission Planning considers a broader set of needs, including needs related to replacement of aging transmission infrastructure.[2182] The Commission further stated that, absent a federal right of first refusal for right-sized replacement transmission facilities, the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely proceed to develop the less efficient or cost-effective in-kind replacement transmission facility because it would prefer the assurance of a federal right of first refusal for the in-kind replacement transmission facility over the uncertainty of subjecting a right-sized replacement transmission facility to the Order No. 1000 competitive transmission development process.[2183] Thus, the federal right of first refusal for right-sized

[2181] *Id.* P 1706.

[2182] *Id.*

[2183] *Id.*

replacement transmission facilities will remove a barrier to development of more efficient or cost-effective regional solutions that could encompass both replacements of aging transmission infrastructure and regional transmission solutions to address Long-Term Transmission Needs. Similarly, the Commission found that requiring the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs will encourage transmission providers to provide their best in-kind replacement estimates because they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility.[2184]

876. The Commission found that, given this incentive structure and the fact that the transmission provider holds the leverage as to whether to build a right-sized replacement transmission facility or a less efficient in-kind replacement transmission facility, the establishment of a federal right of first refusal for right-sized replacement transmission facilities is necessary to effectuate the right-sizing reform and ensure that Commission jurisdictional rates are just and reasonable.[2185] We sustain this finding, and we continue to conclude that a federal right of first refusal for right-sized replacement transmission facilities will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning, helping to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is

[2184] *Id.* P 1703.

[2185] *Id.* P 1706.

selected and likely built, and therefore that the Commission-jurisdictional rates that customers pay are just and reasonable.[2186] As such, we find that the Commission has provided a reasoned explanation for its decision to depart from prior precedent and require a federal right of first refusal for right-sized replacement transmission facilities.

877. We are unpersuaded by Advanced Energy's, Competition Coalition's, and NESCOE's claims regarding the use of the term "rights-of-way" in defining a right-sized replacement transmission facility. As in Order No. 1000, we find that the retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way,[2187] and nothing in the definition of "in-kind replacement transmission facility" or "right-sized replacement transmission facility" would affect the retention, modification, or transfer of rights-of-way. While we recognize Advanced Energy's argument that a right-sized replacement transmission facility may require additional land for a right-of-way, we decline to speculate on land acquisition costs because land acquisition costs vary from transmission facility to transmission facility. In any case, the fact that there may be additional land acquisition costs does not, as Advanced Energy argues, render the definition of a right-sized replacement transmission facility vague. We note, however, that transmission providers could consider the potential for such costs when they are evaluating whether a particular right-sized

[2186] *See id.* P 1703.

[2187] *Id.* P 319.

replacement transmission facility is a more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs.

878. Moreover, we disagree that Order No. 1920's inclusion of the term "general route" in the definition of "in-kind replacement transmission facility" and "right-sized replacement transmission facility" renders those definitions vague. Rather, we find the term "general route," when read in the context of Order No. 1920's example detailing which transmission facilities would be eligible for right-sizing,[2188] makes clear that the right-sizing reform considers existing topology of the transmission system to ensure that the right-sizing reform applies to *replacement* transmission facilities only.[2189] We find that it is important to include this term to provide a reasonable bound of the definition of both in-kind replacement transmission facilities and right-sized replacement transmission facilities. Further, a right-sized replacement transmission facility may require changes to or expansions of rights-of-way to accommodate that right-sized replacement transmission facility, and it is not feasible to list every type or circumstance that may bear upon existing rights-of-way. Accordingly, we find that the requirement for a right-sized replacement transmission facility to also be located in the same general route as the existing transmission facility identified for replacement provides a reasonable limitation on the location of such a right-sized replacement transmission facility. For example, if a transmission provider anticipates replacing an existing transmission facility because it has

[2188] *Id.* P 1680.

[2189] *Id.* PP 1678, 1679.

reached the end of its useful life and the replacement transmission facility (either in-kind or right-sized) requires modifications to that facility's rights-of-way to accommodate other infrastructure projects or avoid environmentally sensitive areas, those modifications to existing rights-of-way are permitted under the term "same general route." We note that Order No. 1920's example relied on interconnection points to describe which in-kind replacement transmission facilities would be eligible for right-sizing,[2190] specifically, that a right-sized replacement transmission facility that connects the same interconnection points to which an in-kind replacement transmission facility connects qualifies under the term "same general route." We reiterate that these limitations are appropriate to ensure that the right-sizing reform applies to *replacement* transmission facilities only. For example, a new transmission facility would not qualify as a right-sized replacement transmission facility if it has significantly different interconnection points than the in-kind replacement facility.

879. Furthermore, we find Competition Coalition's contention that the definition of "right-sized replacement transmission facility" is inconsistent with Order No. 1000 regarding the use of rights-of-way to be inapposite. In Order No. 1000, the Commission stated that the requirement to "eliminate a federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way."[2191] The Commission stated that "[t]he issue is not whether the upgrade would be

[2190] *Id.* P 1680.

[2191] Order 1000-A, 139 FERC ¶ 61,132 at P 427.

located in an existing right-of-way, but whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities."[2192] In other words, the Commission found in Order No. 1000 that whether a regional transmission facility does or does not require the expansion of an existing right-of-way is not relevant to whether that facility is an upgrade. In contrast, for the reasons discussed directly above, in Order No. 1920 the Commission found it necessary that, to qualify as a right-sized replacement transmission facility, a transmission facility must be located in the same general route as, and/or use or expand the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate.

880. We are unpersuaded by Competition Coalition's arguments regarding specific terminology in the right-sizing reform. However, we provide additional context for certain terms and phrases included in the right-sizing reform. We sustain the definition of "right-sizing" to mean "the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability."[2193] The Commission noted that right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double circuit line), or incorporating advanced technologies (such as advanced conductor technologies).[2194] Regarding the other terms

[2192] *Id.*.

[2193] Order No. 1920, 187 FERC ¶ 61,068 at P 1678.

[2194] *Id.* P 1678 n.3580.

highlighted by Competition Coalition, we find that, read in the context of the right-sizing reform, as well as Order No. 1920, these terms are clear, , and we disagree with Competition Coalition that the absence of independent transmission monitor language confirms the need for such an entity in the context of right-sizing.[2195]

881. We grant clarification to Dominion's requests regarding the 200 kV threshold for determining whether a transmission facility is eligible for right-sizing. We clarify that the Commission's finding in Order No. 1920 that the kV threshold must not exceed 200 kV means that transmission providers must include in their in-kind replacement estimates all transmission facilities operating at or above 200 kV that they anticipate replacing in-kind during the next 10 years. We also clarify that transmission providers may establish a threshold *lower* than 200 kV to ensure that a larger number of transmission facilities may be included. Put simply, transmission providers may propose a threshold for all transmission facilities that are eligible to be right-sized, so long as that threshold is under 200 kV.

[2195] The Commission will continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future. *See supra* Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

### 2. Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs

#### a. Order No. 1920

882. In Order No. 1920, the Commission required the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs.[2196] In adopting a federal right of first refusal requirement for a right-sized replacement transmission facility, the Commission noted that a federal right of first refusal is an exception to Order No. 1000's general requirement for transmission providers to eliminate any federal right of first refusal for regional transmission facilities selected in a regional transmission plan.[2197] The Commission explained that requiring a federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level; rather, the Commission found that it will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. Further, the Commission explained that, when compared against the alternative of piecemeal development of in-kind replacement transmission facilities, the right-sized replacement transmission facility represents the more efficient or cost-

[2196] Order No. 1920, 187 FERC ¶ 61,068 at P 1702; *see also supra* Analysis under Section 206 section.

[2197] *Id.* P 1704 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 313).

effective regional transmission solution to address Long-Term Transmission Needs (otherwise it would not be selected).[2198]

883. Additionally, the Commission explained that, in requiring a federal right of first refusal for a right-sized replacement transmission facility, Order No. 1000 did not alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to their own transmission facilities, regardless of whether the upgrade is selected.[2199]

### b. Requests for Rehearing and Clarification

884. Certain parties request rehearing of Order No. 1920's establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs, on the grounds that the Commission deviated from prior precedent without reasoned explanation and, therefore, such requirements are arbitrary and capricious.[2200] For example, Advanced Energy states that the Commission failed to explain how providing for a right of first refusal for right-sized replacement transmission facilities in Order No. 1920 was consistent with prior Commission findings

[2198] *Id.* P 1706.

[2199] *Id.* P 1705 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 319 (internal citation omitted)).

[2200] Advanced Energy Rehearing Request at 15-16; Competition Coalition Rehearing Request at 40-43; Designated Retail Regulators Rehearing Request at 41-42; Industrial Customers Rehearing Request at 9.

that granting an incumbent utility a federal right of first refusal can lead to rates that are unjust and unreasonable.[2201]

885. Advanced Energy further argues that the Commission's provision of a federal right of first refusal for right-sized replacement transmission facilities is inconsistent with the general federal policy against anticompetitive practices.[2202]

886. Relatedly, Advanced Energy, Competition Coalition, and PIOs argue that the inclusion of a federal right of first refusal as part of the right-sizing reform will create incentives for incumbent transmission owners to use the local transmission planning processes to undermine the regional transmission planning process, resulting in less efficient or cost-effective solutions and, therefore, unjust and unreasonable rates.[2203] For instance, Competition Coalition argues that a profit-motivated incumbent transmission owner will have incentives to add even more in-kind replacements into its local transmission plan because of the possibility that the transmission planning region will then right-size those projects into an even larger facility in which the incumbent utility would be allowed to invest without any competition, thus preserving, reinforcing, and expanding its monopoly position.[2204]

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[2201] Advanced Energy Rehearing Request at 16 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 360; *FCC v. Fox Television Stations*, 556 U.S. at 515).

[2202] *Id.* at 10-11; *see also* Competition Coalition Rehearing Request at 67-68.

[2203] Advanced Energy Rehearing Request at 13-14; Competition Coalition Rehearing Request at 69-71; PIOs Rehearing Request at 51-54.

[2204] Competition Coalition Rehearing Request at 69-70.

### c. Commission Determination

887. We are unpersuaded by rehearing requests arguing that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities selected to meet Long-Term Transmission Needs is arbitrary and capricious. In Order No. 1000, the Commission required transmission providers to eliminate federal rights of first refusal because those federal rights of first refusal allowed transmission providers to undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level, which could lead to unjust and unreasonable rates for Commission-jurisdictional services.[2205] Moreover, in Order No. 1000 the Commission found that federal rights of first refusal created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions at the regional level.[2206]

888. In Order No. 1920, the Commission found that that a right-sized replacement transmission facility has the potential to both meet an individual transmission provider's responsibility to maintain the reliability of its existing transmission system and to address a Long-Term Transmission Need more efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility.[2207] The Commission further explained that, compared to the alternative of

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[2205] Order No. 1000, 136 FERC ¶ 61,051 at PP 253, 256, 313.

[2206] *Id.* P 257.

[2207] Order No. 1920, 187 FERC ¶ 61,068 at P 1682.

piecemeal development of in-kind replacement transmission facilities, a federal right of first refusal for right-sized transmission facilities is appropriate because right-sized replacement transmission facilities represent the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs (otherwise, they would not be selected).[2208]

889. We recognize that requiring the federal right of first refusal for right-sized replacement transmission facilities is a departure from the Order No. 1000's requirement that transmission providers eliminate federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation. However, we find the departure, in this instance, to be necessary in order to shift the balance of transmission facility construction and remove a barrier to the selection of more efficient or cost-effective regional transmission facilities. As the Commission found, the existing piecemeal approach to upgrading the transmission system results in inefficiencies and increased rates for consumers.[2209] The Commission is improving the efficiency of the transmission planning process and ensuring rates are just and reasonable by promoting the consideration of right-sized replacement transmission facilities, subject to evaluation and selection processes in Long-Term Regional Transmission Planning, and

[2208] *Id.* P 1706.

[2209] *Id.* PP 1574, 1706.

by establishing the availability of the federal right of first refusal for such right-sized replacement transmission facilities.[2210]

890. We sustain Order No. 1920's finding that the right-sizing reform will promote the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. Specifically, the federal right of first refusal will provide transmission providers with certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility, and this, in turn, will encourage transmission providers to provide their best in-kind replacement estimates.[2211] Accordingly, we continue to find that a federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning, helping to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is identified and selected, and therefore that Commission-jurisdictional rates are just and reasonable.

891. In Order No. 1920, the Commission explained that, in the context of the right-sizing reform, a federal right of first refusal will *promote* the consideration of more

[2210] Although we find that the Commission has supported the inclusion of the right-sizing reforms as a component of a just and reasonable replacement rate, we consider these reforms as an enhancement to, rather than essential to, the Long-Term Regional Transmission Planning process. Absent the right-sizing reforms, the Commission would have established the other Long-Term Regional Transmission Planning requirements as a sufficient just and reasonable replacement rate.

[2211] Order No. 1920, 187 FERC ¶ 61,068 at P 1703.

efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs because, absent the right-sizing reform, those needs would be addressed in a piecemeal manner.[2212] This will in turn benefit consumers by helping to ensure that the rates that they pay are just and reasonable. Furthermore, we believe that providing a federal right of first refusal for selected right-sized replacement transmission facilities is consistent with Order No. 1920's finding that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements causes transmission providers to fail to appropriately evaluate the benefits of transmission infrastructure, and results in piecemeal transmission expansion to address relatively near-term transmission needs.[2213] As such, as discussed in the Eligibility section above, we find that it is appropriate to alter the Commission's policy regarding the removal of the federal right of first refusal by providing a federal right of first refusal for selected right-sized replacement transmission facilities. This is particularly true because the reforms that we require here serve a similar purpose as removing the federal right of first refusal for regional transmission facilities selected in the regional transmission plan for purposes of cost allocation in Order No. 1000. In each instance, the Commission's goal was to ensure that the more efficient or cost-effective regional transmission facilities are considered, thereby ensuring that Commission-jurisdictional rates are just and reasonable – in Order No. 1000, that was accomplished by removing the federal right of first refusal

[2212] *Id.* P 1706.

[2213] *Id.* P 85.

for selected regional transmission facilities in certain instances, while in Order No. 1920, it was by establishing a federal right of first refusal in the limited instances where it incentivizes transmission providers to consider right-sized replacement transmission facilities as more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs. The reforms related to the federal right of first refusal in Order Nos. 1000 and 1920 each seek to ensure that more efficient or cost-effective regional transmission facilities are considered thereby resulting in just and reasonable rates. Protecting consumers and ensuring Commission-jurisdictional rates are just and reasonable are fundamental requirements of the Federal Power Act and we believe that the reforms in Order No. 1920 accomplish these mandates.

892. We also note that this federal right of first refusal applies only to selected right-sized replacement transmission facilities, which, absent the right-sizing reform, would likely not otherwise be identified for potential selection in either the existing Order No. 1000 regional transmission planning process or the Long-Term Regional Transmission Planning process. That is because there is currently no requirement for transmission providers to submit their in-kind replacement transmission facilities to the regional transmission planning process for potential right-sizing. In addition, as the Commission explained in Order No. 1920, the right-sizing reform does not alter existing laws related to an individual transmission provider's ability to proceed with an in-kind replacement transmission facility, and we continue to find that, absent a federal right of first refusal, the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely proceed to develop the less efficient or cost-

effective in-kind replacement transmission facility.[2214] This is because, absent the federal right of first refusal, the incumbent transmission provider would not be assured that it would have the opportunity to invest in the right-sized replacement transmission facility and therefore very likely would chose to build the less efficient or cost-effective in-kind replacement transmission facility. Therefore, the right-sizing reform's federal right of first refusal provides the needed incentives to ensure that in-kind replacement transmission facilities are considered in the Long-Term Regional Transmission Planning process and selected when they are more efficient or cost-effective transmission solutions while also not substantially reducing the number of transmission facilities that would otherwise be subject to a competitive transmission development process.

893. We are also unpersuaded by Advanced Energy's arguments that the federal right of first refusal associated with the right-sizing reform is inconsistent with federal policies against anticompetitive practices. As we note above, given the existing federal rights of first refusal that transmission owners have and that we are not altering here, it is unlikely that right-sized replacement transmission facilities would ever be considered in competitive transmission development processes. Therefore, we do not believe that the right-sizing reform will significantly decrease competition compared to the status quo.

894. We are unpersuaded by rehearing requests that argue that the federal right of first refusal associated with the right-sizing reform will create incentives for incumbent transmission providers to use local transmission planning processes to undermine

[2214] *Id.* P 1706.

regional transmission planning processes. Under Order No. 1920's right-sizing reforms, incumbent transmission owners will have an incentive to identify in-kind replacement transmission facilities that could be right-sized to retain a federal right of first refusal over regional transmission facilities, but that incentive does not undermine the regional transmission planning process. Instead, it will enhance regional transmission planning by expanding the range of potential regional transmission solutions to Long-Term Transmission Needs considered through Long-Term Regional Transmission Planning, facilitating the identification and selection of more efficient or cost-effective regional transmission facilities and helping to ensure just and reasonable Commission-jurisdictional rates. Moreover, because Order No. 1920 requires that a right-sized replacement transmission facility be evaluated in the same manner as any other proposed Long-Term Regional Transmission Facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need,[2215] a right-sized replacement transmission facility will be selected only where it is the more efficient or cost-effective transmission solution. As such, there is no guarantee that an in-kind replacement transmission facility that a transmission provider identifies in its in-kind replacement estimates list will be right-sized and selected. To the extent that the evaluation of a transmission provider's in-kind replacement transmission facility determines that the in-kind replacement transmission facility cannot be right-sized to

[2215] *Id.* P 1681.

more efficiently or cost-effectively address Long-Term Transmission Needs, then it will not be selected as a right-sized replacement transmission facility.

### 3. Confidentiality of In-Kind Replacement Estimates

#### a. Order No. 1920

895. In Order No. 1920, the Commission explained that to the extent customers or stakeholders request access to a transmission provider's list of in-kind replacement estimates, that transmission provider may subject access to that list of in-kind replacement estimates to confidentiality provisions. However, the Commission added that, once transmission providers have determined, as part of Long-Term Regional Transmission Planning, that an in-kind replacement transmission facility can be right-sized to constitute a right-sized replacement transmission facility, the transmission providers must make public the underlying in-kind replacement transmission facility.[2216]

#### b. Requests for Rehearing and Clarification

896. In their rehearing requests, Dominion and Indicated PJM TOs argue that the Commission's decision on confidentiality for in-kind replacement estimate lists fails to adequately address concerns regarding the possible harm caused by release of the in-kind replacement estimate lists.[2217] Both Dominion and Indicated PJM TOs argue that considering the Commission's determination that once a replacement transmission

[2216] Order No. 1920, 187 FERC ¶ 61,068 at P 1736.

[2217] Dominion Rehearing Request at 36-37; Indicated PJM TOs Rehearing Request at 6-7.

facility can be right-sized, that information will be made publicly available to stakeholders, there is limited value in providing the in-kind replacement estimate list to others.[2218]

897. Further, Indicated PJM TOs argue that confidentiality agreements or provisions do not provide adequate protection against the damage of disclosure of in-kind replacement estimate lists since non-disclosure agreements do not impose any specific safeguards on the information disclosed.[2219] Indicated PJM TOs note that the Commission's general Non-Disclosure Agreement for CEII provides that violations of that agreement "may result in criminal or civil sanctions" against the recipient, and the Commission's Model Protective Order provides that "[a]ny violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission."[2220] Indicated PJM TOs argue that the requirement that a transmission owner make public 10-years' worth of replacement information before transmission plans are made public as part of the Long-Term Regional Transmission Planning process gives

[2218] Dominion Rehearing Request at 36-37; Indicated PJM TOs Rehearing Request at 7-8.

[2219] Indicated PJM TOs Rehearing Request at 8-9.

[2220] *Id.* at 9 (citing FERC, CEII General Non-Disclosure Agreement (Apr. 19, 2020), https://www.ferc.gov/media/1928; FERC, Model Protective Order (May 11, 2020), available at https://www.ferc.gov/administrative-litigation-0).

competing developers a competitive advantage that is inconsistent with the FPA's prohibition on undue discrimination and preferences.[2221]

### c. Commission Determination

898. In response to Dominion's and Indicated PJM TOs' arguments regarding the possible harm caused by release of the in-kind replacement estimate lists, we continue to find that existing rules governing confidential or commercially sensitive information provide for the safekeeping of that information. We note that Order No. 890 required transmission providers, in consultation with affected parties, to develop mechanisms like confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.[2222] To the extent that transmission providers believe that existing provisions are inadequate, they may submit an FPA section 205 filing with additional protections, and the Commission will evaluate them to ensure they are just and reasonable and otherwise comply with the applicable requirements. Moreover, in determining that disclosure of in-kind replacement estimate lists may occur subject to confidentiality provisions, the Commission balanced concerns about disclosure against the importance of transparency and meaningful stakeholder participation in regional transmission planning and cost allocation processes, as required under Order Nos. 890 and 1000. We continue to find, consistent with prior precedent, that disclosure

[2221] *Id.* at 10.

[2222] Order No. 890, 118 FERC ¶ 61,119 at P 460.

subject to appropriate mechanisms for confidentiality strikes an appropriate balance between these interests.[2223]

## XII. Interregional Transmission Coordination

### A. Order No. 1920

899. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in Order No. 1920. More specifically, the Commission required transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes, as needed) to provide for: (1) the sharing of information regarding their respective Long-Term Transmission Needs, as well as Long-Term Regional Transmission Facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs.[2224]

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[2223] *Tri-State Generation & Transmission Ass'n*, 170 FERC ¶ 61,222, at P 27 (2020); *see also Astoria Generating Co. v. N.Y. Indep. Sys. Operator, Inc.*, 136 FERC ¶ 61,155, at PP 21-25 (2011) (adopting protective order and directing respondent to file confidential information and simultaneously release the information to parties who signed non-disclosure certificate); *Pac. Gas Transmission Co.*, 44 FERC ¶ 61,209, at 61,766-67 (1988) (remanding matter to administrative law judge with direction to balance potential harm of disclosing confidential business information sought during discovery against the requesting parties' need for the information).

[2224] Order No. 1920, 187 FERC ¶ 61,068 at P 1751.

Additionally, the Commission required transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes, as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to Long-Term Transmission Needs.[2225]

900. The Commission also required transmission providers in each transmission planning region to provide certain additional information concerning Long-Term Regional Transmission Planning on their public websites or through the email list used for communication of information related to interregional transmission coordination procedures.[2226]

### B. Comments

901. In its comments, Grid United argues that Order No. 1920 does not solve the challenges of developing transmission, including interregional transmission, and requests that the Commission open a new proceeding focused on interregional transmission and its challenges.[2227]

### C. Commission Determination

902. Although we acknowledge Grid United's request that the Commission continue to build upon the progress in Order No. 1920 for regional transmission planning by

[2225] *Id.* P 1752.

[2226] Order No. 1920, 187 FERC ¶ 61,068 at P 1753.

[2227] Grid United June 12, 2024 Comments at 1-2.

addressing interregional transmission, we decline to open a new docket at this time, as requested by Grid United.[2228] We find that Order No. 1920 adequately addressed the interregional transmission coordination reforms needed to account for the rule's Long-Term Regional Transmission Planning reforms.[2229] In particular, we continue to find that the reforms in Order No. 1920, taken together, will ensure that Long-Term Transmission Needs identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes, and that there is an opportunity for transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively address the identified Long-Term Transmission Needs, helping to ensure just and reasonable Commission-jurisdictional rates.[2230] Furthermore, as the Commission found in Order No. 1920, and we reiterate here, the Commission currently has an open proceeding in Docket No. AD23-3-000 to consider whether and how to establish a minimum requirement for Interregional Transfer Capability including the transmission planning and cost allocation related to such a requirement.[2231] To the

[2228] As noted above, the pleading filed by Grid United is deficient under 18 CFR 385.712(c)(2). Nevertheless, we address Grid United's arguments to provide clarity. *See infra* Introduction and Background section.

[2229] Order No. 1920, 187 FERC ¶ 61,068 at PP 1740-1758.

[2230] *Id.* P 1754.

[2231] *See* Supplemental Notice of Staff-Led Workshop, *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Docket No. AD23-3-000 (Nov. 30, 2022).

extent that the Commission determines that further investigation of this issue is warranted, it can open a new docket at an appropriate time or consider such issues in pending proceedings,[2232] as appropriate.

## XIII. Compliance Procedures

### A. Order No. 1920

903. In Order No. 1920, the Commission required each transmission provider to submit a compliance filing revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets all of the requirements adopted in Order No. 1920, except those adopted in the Interregional Transmission Coordination section above, within 10 months of the effective date of Order No. 1920. The Commission explained that a 10-month compliance period allows transmission providers to fully develop proposals to comply with Order No. 1920 and allows stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. Additionally, the Commission required transmission providers in each transmission planning region to propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning

[2232] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1758 ("[W]e note that the Commission currently has an open proceeding in Docket No. AD23-3-000 to consider whether and how to establish a minimum requirement for Interregional Transfer Capability, and may consider further reforms in other proceedings, as appropriate.").

cycle.[2233] The Commission noted, however, that transmission providers may propose an earlier effective date for some or all parts of their revised OATTs to allow them to begin implementing any aspects of the required reforms sooner than the one-year deadline to commence the first Long-Term Regional Transmission Planning cycle.[2234]

904. The Commission further required each transmission provider to submit a compliance filing revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements within 12 months of the effective date of Order No. 1920. The Commission explained that a longer compliance timeframe will allow transmission providers to coordinate with the transmission providers in each of their neighboring transmission planning regions to develop interregional transmission coordination proposals.[2235]

905. Additionally, the Commission required transmission providers that are not public utilities to adopt the requirements of Order No. 1920 as a condition of maintaining the

[2233] Order No. 1920, 187 FERC ¶ 61,068 at P 1768. The Commission noted that Order No. 1920 required transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with Order No. 1920 are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles). *Id.*

[2234] *Id.* P 1768.

[2235] *Id.* P 1770.

status of their safe harbor tariffs or otherwise satisfying the reciprocity requirement of Order No. 888.[2236]

906. Finally, in Order No. 1920, the Commission explained that it made no changes to the standards used to judge requested variations, as described in Order Nos. 888, 2000, 890, and 1000 and, accordingly, declined a request to apply the independent entity variation standard, rather than the "consistent with or superior to" standard, for proposed deviations from the requirements of Order No. 1920.[2237] The Commission stated that, consistent with findings in Order No. 890, the Commission will continue to apply the "consistent with or superior to" standard in the context of transmission planning.[2238] The Commission explained that, to the extent that a transmission provider believes that it already complies with any of the requirements in Order No. 1920, it should describe in its compliance filing how the relevant requirements are satisfied, including by referencing specific tariff sheets already on file with the Commission.[2239]

[2236] *Id.* P 1771 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63).

[2237] *Id.* P 1772 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769-70; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 1000, 136 FERC ¶ 61,051 at P 815).

[2238] *Id.* P 1772 (citing Order No. 890, 118 FERC ¶ 61,119 at P 160).

[2239] *Id.* P 1773.

### B. Requests for Rehearing and Clarification

907. Dominion and NARUC request rehearing of Order No. 1920's compliance timeframes.[2240] Dominion argues that the Commission failed to consider that many of the same personnel responsible for implementing Order No. 2023 are also responsible for managing the implementation of Order No. 1920's requirements.[2241] NARUC asserts that Order No. 1920's 10-month compliance deadline is insufficient to allow state entities to meaningfully engage on developing cost allocation proposals given existing state retail regulatory duties, the steep learning curve on issues related to Order No. 1920, and internal legal and procedural issues they will need to sort through. NARUC suggests that the record justifies a 14-month compliance period.[2242]

908. Dairyland and PJM request rehearing of Order No. 1920's requirement that transmission providers demonstrate proposed deviations from the requirements of Order No. 1920 are "consistent with or superior to" the requirements of Order No. 1920.[2243] Both Dairyland and PJM request that the Commission adopt an independent entity variation standard for compliance with the final rule. Dairyland argues that the Commission failed to consider information and arguments submitted in support of the

[2240] Dominion Rehearing Request at 37-39; NARUC Rehearing Request at 18-21.

[2241] Dominion Rehearing Request at 38 (citing *State Farm*, 463 U.S. at 43).

[2242] NARUC Rehearing Request at 20-21.

[2243] Dairyland Rehearing Request at 3-7; PJM Rehearing Request at 10-14.

independent entity variation[2244] and made no attempt to explain why the precedent of Order No. 2003, which identified bases for a different compliance standard for independent entities, is distinguishable or should not be used here.[2245] Along similar lines, PJM argues that aspects of Order No. 1920 are arbitrary and capricious because: (1) the final rule is internally inconsistent given the Commission's recognition of the need for regional flexibility while also including "numerous prescriptive requirements" and rejecting requests to apply an "independent entity variation" standard of review and instead applying the "consistent with or superior to" standard for proposed deviations from the final rule;[2246] and (2) the Commission failed to consider the evidence offered by ISO/RTOs that they need flexibility to implement Long-Term Regional Transmission Planning.[2247]

909. APPA and TAPS request clarification of Order No. 1920's requirements for consultation with stakeholders.[2248] APPA requests that the Commission clarify that transmission providers have an obligation to consult with stakeholders—including public power entities and load-serving entities—in developing compliance filings.[2249] TAPS

[2244] Dairyland Rehearing Request at 4.

[2245] *Id.* at 3-4, 6-7; *see also* PJM Rehearing Request at 13 n.60.

[2246] PJM Rehearing Request at 10-11, 41; *see also* Dairyland Rehearing Request at 7.

[2247] PJM Rehearing Request at 11-14, 42.

[2248] APPA Rehearing Request at 6-7; TAPS Rehearing Request at 14-19.

[2249] APPA Rehearing Request at 7.

requests the Commission to clarify that Order No. 1000's general obligation to consult with stakeholders in developing the associated transmission provider's compliance filing applies to all aspects of Order No. 1920 compliance filings, including the evaluation process, selection criteria, and the calculation of benefits.[2250]

910. In its rehearing request, Large Public Power argues that the Commission should clarify that non-public utilities can satisfy the reciprocity requirement of Order No. 888 through one of three means: (1) providing service to a public utility transmission provider under a safe harbor tariff; (2) providing service under a bilateral agreement; or (3) seeking waiver.[2251]

911. SPP requests clarification from the Commission that SPP can deviate from the specific requirements of Order No. 1920 and propose its own Consolidated Planning Process. SPP requests that the Commission clarify that a transmission provider may propose on compliance a new transmission planning process and cost allocation method that deviates from the requirements of Order No. 1920, and that the Commission could issue an order approving such a cost allocation process as consistent with or superior to the requirements of Order No. 1920.[2252]

912. WIRES states that the Commission should grant clarification or, in the alternative, rehearing, that transmission providers are not required to implement the proposed tariff

[2250] TAPS Rehearing Request at 18-19.

[2251] Large Public Power Rehearing Request at 23-24.

[2252] SPP Rehearing Request at 2-4.

revisions submitted in compliance with Order No. 1920 until the Commission issues "a final order on compliance."[2253] WIRES states that Order No. 1920 could be read to create a scenario where transmission providers would be required to begin implementing their OATT provisions submitted in compliance with the requirements of Order No. 1920 *before* receiving a Commission order on compliance accepting such revised Tariff provisions. WIRES argues that this would put transmission providers in the untenable position of expending a significant amount of time and resources in implementing Long-Term Regional Transmission Planning cycles that the Commission could find in a later order are not compliant with Order No. 1920.[2254]

913. Versant Power requests that the Commission clarify, or in the alternative grant rehearing, regarding: (1) what is generally required for a transmission provider to receive a waiver of Order No. 1920's requirements; and (2) whether and how waivers of previous, relevant orders affect Order No. 1920's requirements for transmission providers with those waivers.[2255]

### C. Commission Determination

914. We sustain Order No. 1920's requirement that each transmission provider submit a compliance filing within 10 months of the effective date of Order No. 1920 revising its

[2253] WIRES Rehearing Request at 5-6, 16-18.

[2254] WIRES Rehearing Request at 16-18.

[2255] Versant Power Rehearing Request at 9-16. Versant Power notes that its request for clarification may be withdrawn because of a separate waiver filing. *Id.* at 1 n.4. Versant Power withdrew its rehearing request on September 10, 2024.

OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in Order No. 1920, except those requirements adopted in the Interregional Transmission Coordination section above. As we noted in Order No. 1920, we continue to find that a 10-month compliance period will allow transmission providers adequate time to fully develop proposals to comply with Order No. 1920.[2256] We also sustain Order No. 1920's requirement that each transmission provider submit a separate compliance filing within 12 months of the effective date of Order No. 1920 revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in Order No. 1920.[2257] Nevertheless, as noted above in the Duration of the Engagement Period section above, if we grant an extension of the required Engagement Period when Relevant State Entities make a showing that they require additional time to finalize cost allocation discussions, we will also, as appropriate, extend, *sua sponte*, the relevant Order No. 1920 compliance deadlines to ensure that any extension of the Engagement Period would not conflict with the required compliance deadlines.

915. We clarify that the effective date associated with this order on rehearing and clarification does not extend the relevant compliance deadlines associated with Order No. 1920. In calculating the required dates for compliance filings (e.g., 10 months for

[2256] Order No. 1920, 187 FERC ¶ 61,068 at P 1768.

[2257] *Id.* P 1770.

revisions to a transmission provider's OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in Order No. 1920, and 12 months for revisions to a transmission provider's OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in Order No. 1920), transmission providers should use the effective date of Order No. 1920 (i.e., August 12, 2024) and not the effective date for the changes to Order No. 1920 made in this order on rehearing and clarification.

916. We are unpersuaded by Dominion's and NARUC's arguments that the Commission should require a longer compliance period. We note that in Order No. 1920 the Commission modified the NOPR proposal for an eight-month compliance period to allow an additional two months.[2258] While we appreciate Dominion's concerns regarding personnel responsible for implementing both Order Nos. 1920 and 2023, we believe that we have provided sufficient time for transmission providers to develop compliance filings.

917. We also sustain Order No. 1920's requirement that, consistent with the Commission's findings in Order No. 890, transmission providers must demonstrate that proposed deviations from the requirements of Order No. 1920 are "consistent with or superior to" the requirements in Order No. 1920.[2259]

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[2258] *Id.* P 1768.

[2259] *Id.* P 1772 (citing Order No. 890, 118 FERC ¶ 61,119 at P 160).

918. We disagree with Dairyland's assertion that the Commission's use of the "consistent with or superior to" standard in Order No. 1920 is an unexplained departure from Commission precedent.[2260] To the contrary, in Order No. 1920, the Commission made no changes to the standard used to judge requested variations in the context of transmission planning, including in Order Nos. 888, 2000, 890, and 1000,[2261] and instead followed precedent in applying the "consistent with or superior to" standard of review to proposed new and existing variations from its transmission planning and cost allocation requirements.[2262] Rather, allowing for the use of the independent entity variation standard of review in this proceeding, as Dairyland and PJM request, would be a departure from this line of precedent and an importation of the independent entity variation standard from the interconnection context into the transmission planning context that would require further explanation.[2263] As discussed below, neither Dairyland nor PJM justify such a departure.

919. Further, we disagree with PJM's and Dairyland's claims that Order No. 1920 is internally inconsistent because it recognizes the need for regional flexibility while also including prescriptive requirements without allowing for independent entity

[2260] Dairyland Rehearing Request at 3, 6.

[2261] Order No. 1000, 136 FERC ¶ 61,051 at P 815; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769-70.

[2262] Order No. 1920, 187 FERC ¶ 61,068 at P 1772.

[2263] *See FCC v. Fox Television Stations, Inc.*, 556 U.S. at 515.

variations.[2264] In a number of areas, Order No. 1920 provides transmission providers with the flexibility to accommodate regional differences, and this flexibility can be incorporated into the regional transmission planning requirements.[2265] Although in other areas the Commission provided less flexibility, we believe that the Commission struck a reasonable overall balance in Order No. 1920 between, on the one hand, transmission providers' need for flexibility in implementing Long-Term Regional Transmission Planning in their transmission planning regions and, on the other hand, ensuring that transmission providers adopt reforms that will result in transmission providers identifying, evaluating, and selecting more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs and thus Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.[2266]

920. We are unpersuaded by PJM's and Dairyland's arguments that the rationale for application of the independent entity variation standard to RTOs/ISOs in the

[2264] PJM Rehearing Request at 11-12; Dairyland Rehearing Request at 7.

[2265] For example, Order No. 1920 provides for flexibility such as: (1) allowing transmission providers to measure and use additional benefits in Long-Term Regional Transmission Planning; (2) allowing transmission providers to develop evaluation processes and selection criteria that can accommodate regional differences; and (3) declining to impose a selection requirement as transmission providers require the flexibility to balance competing interests in the transmission planning region and to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements. *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 729, 924, 1027.

[2266] Order No. 1920, 187 FERC ¶ 61,068 at P 237.

interconnection context in Order No. 2003 applies equally to the circumstances of Order No. 1920.[2267] The requirements of Order No. 2003 were established to achieve greater standardization of interconnection terms and conditions and to address evidence of undue discrimination in interconnection processes.[2268] The Commission granted independent entities greater flexibility to deviate from the provisions of the *pro forma* OATT on the basis that these entities do not own generation and therefore face fewer incentives to act in an unduly discriminatory or preferential manner toward certain generators.[2269] That rationale does not apply to the requirements in Order No. 1920, which were adopted to address deficiencies in regional transmission planning processes, as those processes fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs and therefore to ensure just and

[2267] PJM Rehearing Request at 13 n.60 (citing *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220, at PP 756, 759, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277; *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at P 1764, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024)); Dairyland Rehearing Request at 5, 6 (citing MISO NOPR Reply Comments at 5-8).

[2268] Order No. 2003, 104 FERC ¶ 61,103 at PP 11-12.

[2269] *Id.* PP 822, 827; Order No. 2003-A, 106 FERC ¶ 61,220 at P 759.

reasonable rates.[2270] The need for regional transmission planning processes that meet the Commission's requirements in Order No. 1920 applies to all transmission providers to the same extent regardless of their independence or complexity. Beyond noting the independence and complexity of RTOs/ISOs, neither PJM nor Dairyland have justified or offered evidence of why RTOs/ISOs should be treated differently than other transmission providers for purposes of compliance with Order No. 1920's requirements.

921. However, in light of PJM's and Dairyland's arguments, we clarify that, in analyzing Order No. 1920 compliance filings, we will apply the "consistent with or superior to" standard to proposed variations from *all* requirements of Order No. 1920 and not limit the standard to proposed variations from *pro forma* OATT provisions developed in Order No. 1920. Consistent with Commission practice,[2271] it is appropriate to apply

[2270] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 87, 89.

[2271] *See, e.g.*, *Pub. Util. Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 84 FR 65281 (Nov. 27, 2019), 169 FERC ¶ 61,139, at P 66 n.101 (2019), *order on reh'g*, Order No. 864-A, 85 FR 27681 (May 11, 2020), 171 FERC ¶ 61,033 (2020); *Uplift Cost Allocation & Transparency in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 844, 83 FR 18134 (Apr. 25, 2018), 163 FERC ¶ 61,041, at P 103 (2018); *Settlement Intervals & Shortage Pricing in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 825, 81 FR 42882 (June 30, 2016), 155 FERC ¶ 61,276, at PP 88, 90 (2016); Order No. 1000, 136 FERC ¶ 61,051 at P 583 n.452; *Demand Response Comp. in Organized Wholesale Energy Mkts.*, 76 FR 16658 (Mar. 24, 2011), Order No. 745, 134 FERC ¶ 61,187, at P 4 n.7; *order on reh'g & clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. EPSA*, 577 U.S. 260; *Regional Transmission Orgs.*, Order No. 2000, 65 FR 810 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089, at 31,164 (1999) (amending 18 CFR 35.34(k)(1)-(2), (k)(4), (k)(6)-(7)), *order on reh'g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub*

the "consistent with or superior to" standard both to variations from *pro forma* OATT provisions and to variations from requirements not accompanied by *pro forma* OATT provisions (i.e., those requirements that transmission providers must satisfy by developing or revising their own OATT provisions). The "consistent with or superior to" standard "is a tool for ensuring that a proposed tariff revision will still meet the standards of the FPA" despite varying from the "minimum provisions necessary" to ensure just, reasonable, and not unduly discriminatory or preferential Commission-jurisdictional rates.[2272] Both *pro forma* OATT provisions and requirements not accompanied by *pro forma* OATT provisions set "common starting point[s]"[2273] to ensure that Commission-jurisdictional rates satisfy the requirements of the FPA. The Commission will review proposed variations from requirements established in Order No. 1920 to ensure that they continue to meet the requirements of FPA sections 205 and 206.

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*nom. Pub. Util. Dist. No. 1 of Snohomish Cty. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[2272] *N.Y. State Elec. & Gas Corp.*, 78 FERC ¶ 61,114 (1997), *order on reh'g*, 82 FERC ¶ 61,209, at 61,822 n.4 (1998) (rejecting proposed deviations from the *pro forma* OATT and explaining that the "consistent with or superior to" inquiry does not impermissibly supplant or narrow the "just and reasonable" standard; rather, it evaluates whether a proposed deviation from the "common starting point" set out in a rule is consistent with or superior to that "common starting point" and therefore remains just and reasonable); *Commonwealth Edison Co.*, 83 FERC ¶ 61,274, at 62,143 (1998) (citing *N.Y. State Elec. & Gas Corp.*, 82 FERC at 61,822 & n.4). *See also Xcel Energy Servs. Inc. v. FERC*, 41 F.4th 548, 557-58 (D.C. Cir. 2022) (explaining that the Commission has used its "broad discretion" to craft the "consistent with or superior to" standard to assess whether proposed deviations are just, reasonable, and not unduly discriminatory).

[2273] *N.Y. State Elec. & Gas Corp.*, 82 FERC at 61,822 n.4.

922. In response to SPP's clarification request regarding its own Consolidated Planning Process, we reiterate that Order No. 1920 requires transmission providers to demonstrate that proposed deviations from Order No. 1920 are "consistent with or superior to" the requirements in Order No. 1920.[2274] To the extent that a transmission provider, like SPP, believes that its existing practices or potential provisions submitted as part of its compliance filing deviate from Order No. 1920's requirements, it must demonstrate that any such deviations, including any existing processes or OATT provisions, are consistent with or superior to the requirements of Order No. 1920.

923. We grant APPA's and TAPS' requests for clarification on the role of stakeholders in developing transmission providers' compliance filings. Specifically, we clarify that transmission providers must consult with their stakeholders to develop the processes, procedures, and OATT revisions necessary to comply with Order No. 1920.[2275] We note that this requirement is consistent with the approach that the Commission took in Order Nos. 890 and 1000.[2276]

924. We grant Large Public Power's clarification request regarding reciprocity. Order No. 1920 required that transmission providers that are not public utilities must adopt the

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[2274] Order No. 1920, 187 FERC ¶ 61,068 at P 1772.

[2275] We note that the requirement for transmission providers to consult with stakeholders to develop their compliance filings is separate from and in addition to Order No. 1920's requirement for transmission providers to conduct an Engagement Period for Relevant State Entities, as discussed in the Cost Allocation section above.

[2276] *See., e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 582; Order No. 1000, 136 FERC ¶ 61,051 at PP 151, 206, 227, 336, 588, 793.

requirements of Order No. 1920 as a condition of maintaining the status of their safe harbor tariffs or otherwise satisfy the reciprocity requirement of Order No. 888.2277 As relevant to Large Public Power's clarification request, Order No. 888 provides that a non-public transmission provider may satisfy the reciprocity condition in one of three ways: (1) it may provide service under a tariff that has been approved by the Commission under the voluntary "safe harbor" provision of the *pro forma* OATT; (2) it may provide service to a public utility transmission provider under a bilateral agreement; or (3) it may seek a waiver of the reciprocity condition from the transmission provider.2278

925. Issues concerning effective dates are most appropriately addressed in specific compliance proceedings and, therefore, we decline to grant WIRES' clarification request. However, as explained in the Implementation of Long-Term Regional Transmission Planning section above, we set aside, in part, Order No. 1920's requirement that transmission providers in each transmission planning region must propose on compliance a date, no later than one year from the date on which initial filings to comply with the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle[2279] and instead require transmission providers to propose on compliance a date, no later than *two* years from the date on which initial filings to comply

[2277] Order No. 1920, 187 FERC ¶ 61,068 at P 1771 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63).

[2278] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

[2279] Order No. 1920, 187 FERC ¶ 61,068 at P 1072.

with Order No. 1920 are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. Because we sustain Order No. 1920's requirement that transmission providers must propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle,[2280] we note that this modification should help to address WIRES' concern.

926. We note that Versant Power's rehearing request has been withdrawn.[2281] Nevertheless, we clarify that, consistent with Order No. 890 and Order No. 1000, entities that have existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888, as well as entities that have been granted waiver of the regional transmission planning requirements of Order No. 1000, do not also have to seek waiver of Order No. 1920.[2282] This clarification,

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[2280] Order No. 1920, 187 FERC ¶ 61,068 at P 1768.

[2281] *See* Versant Power September 10, 2024 Notice of Withdrawal. Pursuant to Rule 216 of the Commission's Rules of Practice and Procedure, the withdrawal of any pleading is effective at the end of 15 days from the date of the filing if no motion in opposition to the notice of withdrawal is filed within that period and if the Commission takes no action disallowing withdrawal. 18 CFR 385.216. No motion in opposition to Versant Power's Notice of Withdrawal has been filed, and its request for rehearing accordingly is withdrawn.

[2282] Order No. 1000-A, 139 FERC ¶ 61,132 at P 753 & n.880 (2012); *see also* Order No. 890, 118 FERC ¶ 61,119 at P 135 n.105 ("The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the pro forma OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be

however, is not meant to affect the ability of an entity that does not have an existing waiver to seek one. The Commission will consider requests for waiver of Order No. 1920 on a case-by-case basis from any entity that believes it meets the criteria for such waiver.

## XIV. Overarching Logical Outgrowth Challenges

### A. Requests for Rehearing

927. Several rehearing parties argue broadly that Order No. 1920 is not a logical outgrowth of the NOPR and therefore violates the notice-and-comment requirements of the APA.[2283] Arizona Commission asserts that the Commission failed to provide notice of and opportunity to comment on six "fundamental" changes between the NOPR and Order No. 1920 and that, because such changes are not logical outgrowths of the NOPR, the Commission violated the APA's notice-and-comment requirements, rendering Order No. 1920 unlawful.[2284] Specifically, Arizona Commission alleges that Order No. 1920, unlike the NOPR: (1) imposed preferential and corporate-driven costs on consumers in non-consenting states by requiring the filing of one or more *ex ante* cost allocation methods to apply to selected Long-Term Transmission Facilities; (2) mandated a specific

revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.").

[2283] Arizona Commission Rehearing Request at 18-19 (citing 5 U.S.C. 706(2)(A), (C), (D)); Designated Retail Regulators Rehearing Request at 44, 49 (citing 5 U.S.C. 553); NRECA Rehearing Request at 6, 19 (citing 5 U.SC. 553).

[2284] Arizona Commission Rehearing Request at 18-19.

set of "planning criteria" and purported benefits, which is "simply a way of 'pre-cooking' outcomes"; (3) abandoned regional cost allocation principle (6); (4) effectively eliminated the use of a voluntary State Agreement Process; (5) left the CWIP incentive intact; and (6) made local transmission planning less transparent.[2285]

928. NRECA alleges that Order No. 1920 violated the APA's notice-and-comment requirements by: (1) mandating that transmission providers use a set of seven required benefits for evaluating and selecting Long-Term Regional Transmission Facilities; (2) imposing specific requirements for limited reevaluation of previously selected Long-Term Regional Transmission Facilities; (3) requiring that certain interconnection-related transmission needs must be evaluated for selection in existing Order No. 1000 regional transmission planning and cost allocation processes; (4) not requiring Long-Term Regional Transmission Planning cost allocation methods to comply with all of the Commission's six regional cost allocation principles; and (5) substantially diminishing the proposed role of state regulators in Long-Term Regional Transmission Planning and cost allocation.[2286] NRECA requests that the Commission withdraw Order No. 1920 and issue a supplemental NOPR because "so many of [Order No. 1920's] key provisions" are "brand new" and were not subjected to public comment.[2287]

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[2285] Arizona Commission Rehearing Request at 18-19. *Id.*

[2286] NRECA Rehearing Request at 6.

[2287] *Id.* at 19.

929. Designated Retail Regulators contend that Order No. 1920 contains a number of significant changes that drastically depart from the NOPR, rendering the final rule "surprisingly distant" from and not a logical outgrowth of the NOPR, in violation of the APA's notice-and-comment requirements.[2288] Designated Retail Regulators add that Order No. 1920 "is in essence a new rule that requires new opportunities for comment and input."[2289] Designated Retail Regulators claim that Order No. 1920 differs from the NOPR because Order No. 1920: (1) declined to adopt the NOPR proposal requiring transmission providers to seek the agreement of Relevant State Entities and substantially diminished Relevant State Entity involvement in cost allocation; (2) provided transmission providers complete discretion to decide whether to file a State Agreement Process or Long-Term Regional Transmission Cost Allocation Method in its tariff, even if agreed to by Relevant State Entities; and (3) did not require transmission providers to obtain the support of Relevant State Entities prior to proposing an evaluation process and selection criteria on compliance.[2290]

### B. Commission Determination

930. We disagree with Arizona Commission's, Designated Retail Regulators', and NRECA's arguments that Order No. 1920 violates the APA's notice-and-comment

[2288] Designated Retail Regulators Rehearing Request at 46-50 (quoting *Int'l Union, United Mine Workers of Am. v. Mine Safety and Health Admin.*, 407 F.3d 1250, 1260 (D.C. Cir. 2005)).

[2289] *Id.* at 10.

[2290] *Id.* at 46-50.

requirements and is not a logical outgrowth of the NOPR. Relatedly, we decline to adopt NRECA's suggestion that the Commission withdraw Order No. 1920 in its entirety and issue a supplemental NOPR. As an initial matter, rehearing parties' conclusory arguments lack the specificity required to satisfy FPA section 313(a), which states that an "application for rehearing shall set forth *specifically* the ground or grounds upon which such application is based."[2291] In claiming that Order No. 1920 violated the APA's notice-and-comment requirements, rehearing parties merely point to sections or provisions of Order No. 1920 that allegedly run afoul of those requirements and then assert, without support or further explanation, that Order No. 1920, as a whole, violates the APA's notice-and-comment provision. Arizona Commission, Designated Retail Regulators, and NRECA do not cite, and we are unaware of, any precedent supporting what appears to be their claim that cumulative logical outgrowth challenges to individual provisions would compel a finding that Order No. 1920, as a whole, is not a logical outgrowth of the NOPR. Accordingly, we reject this sweeping argument as lacking the specificity required on rehearing.[2292]

931. In any event, these arguments also lack merit. As discussed throughout this order, the individual provisions of Order No. 1920, which certain rehearing parties claim the

[2291] 16 U.S.C. 825*l*(a) (emphasis added).

[2292] A rehearing request must set forth with specificity the grounds on which the request is based. 16 U.S.C. 825*l*(a); 18 CFR 385.713(c)(2) (2024); *see ZEP Grand Prairie Wind, LLC*, 183 FERC ¶ 61,150, at P 10; *Ind. Util. Regul. Comm'n v. FERC*, 668 F.3d at 738-40.

Commission adopted without adequate notice and opportunity to comment, are, in fact, logical outgrowths of the NOPR and otherwise satisfy the APA's notice-and-comment requirements.[2293] Thus, given that the constituent components of Order No. 1920 satisfy the APA's notice-and-comment requirements, the sum of those components—i.e., Order No. 1920 as a whole—necessarily also satisfies these requirements, and rehearing parties have not shown otherwise.

## XV. Information Collection Statement

932. The Paperwork Reduction Act[2294] requires each Federal agency to seek and obtain the Office of Management and Budget's (OMB) approval before undertaking a collection of information directed to 10 or more persons or contained in a rule of general applicability. OMB regulations require approval of certain information collection requirements contained in final rules published in the *Federal Register*.[2295] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this order on rehearing

[2293] *See supra* Requirement for Transmission Providers to Use and Measure a Set of Seven Required Benefits section; Minimum Requirements section; Role of Relevant State Entities section; Reevaluation section; Transmission Planning Process Evaluation section; Obligation to File an *Ex Ante* Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section; Design and Operation of the Engagement Period section; Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities section; General Benefits Requirements Related to Cost Allocation section; CWIP section.

[2294] 44 U.S.C. 3501-3521.

[2295] *See* 5 CFR 1320.12 (2024).

will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

933. **Summary:** On rehearing of Order No. 1920, the Commission is further revising the *pro forma* OATT to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements. This order on rehearing addresses arguments raised on rehearing, sets aside, in part, and clarifies Order No. 1920. The information collection requirements included in Order No. 1920 were previously approved by OMB under the FERC information collection number FERC-917: *Electric Transmission Facilities* (OMB Control No. 1902-0233). Order No. 1920 required transmission providers to conduct Long-Term Regional Transmission Planning to ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

934. Previously, the Commission submitted to OMB the information collection requirements arising from Order No. 1920, and OMB approved those requirements. In this order on rehearing, the Commission makes five substantive changes to those requirements. In Order No. 1920, the Commission required transmission providers in each transmission planning region to incorporate seven specific categories of factors in the development of Long-Term Scenarios.[2296] Here, we set aside, in part, the requirement for transmission providers to incorporate seven specific categories of factors in the

[2296] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

development of Long-Term Scenarios by excluding corporate commitments from Factor Category Seven. We no longer require transmission providers to separately identify corporate commitments as a factor in their development of Long-Term Scenarios given that the effects of such commitments will be sufficiently incorporated in Long-Term Regional Transmission Planning through the incorporation of other Factor Categories.

935. In Order No. 1920, the Commission required transmission providers in each transmission planning region to develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios.[2297] Here, we clarify that transmission providers, when requested by Relevant State Entities in a transmission planning region, are required to conduct a reasonable number of additional analyses or scenarios, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es).

936. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios.[2298] In addition, the Commission required

[2297] *Id.* P 559.

[2298] *Id.* P 528.

transmission providers to post this information after stakeholders, including states, have had the meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.[2299] Here, we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios.

937. In Order No. 1920, the Commission required transmission providers' evaluation processes, including selection criteria, to be transparent and not unduly discriminatory, and the Commission explained that transmission providers' evaluation of Long-Term Regional Transmission Facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) was selected or not selected.[2300] Here, we clarify that, once a transmission provider makes a selection decision, i.e., for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities), and, if a State Agreement Process is used, once a cost allocation method is agreed upon, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown

[2299] *Id.* P 533.

[2300] *Id.* P 954

of how those estimated costs will be allocated, by zone (i.e., by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of those estimated benefits as imputed to each zone, as such benefits can be reasonably estimated.

938. In Order No. 1920, the Commission declined to require future Engagement Periods, but noted that transmission providers may hold future Engagement Periods if they believe that such periods would be beneficial.[2301] Here, we set aside Order No. 1920, in part, and require that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

939. **Public Reporting Burden:** The estimated burden and cost for the requirements contained in this order on rehearing follow.

| **Changes Due to Order on Rehearing in Docket No. RM21-17-001[2302]** | | | | |
|---|---|---|---|---|
| **A. Area of Modification** | **B. Annual Number of Respondents** | **C. Total Annual Estimated Number** | **D. Average Burden Hours & Cost[2303] per Response** | **E. Total Estimated Burden Hours & Total Estimated Cost** |

[2301] Order No. 1920, 187 FERC ¶ 61,068 at P 1368.

[2302] In the table, Year 1 figures are one-time implementation hours and cost. "Subsequent years" show ongoing burdens and costs starting in Year 2.

[2303] The hourly cost (for salary plus benefits) uses the figures from the Bureau of

| | | of Responses | | (Column C x Column D) |
|---|---|---|---|---|
| **FERC-917, Electric Transmission Facilities (OMB Control No. 1902-0233)** | | | | |
| Establish a six-month time period during which transmission providers must, among other things, provide a forum for negotiation that enables participation by Relevant State Entities and to discuss potential Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process. Also require transmission providers to consult with Relevant State Entities prior to amending Long-Term Regional Transmission Cost Allocation Methods and/or State Agreement Process on file with the Commission. | 48 transmission providers with OATTs | 48 | One Time: 390 hours; $36,307<br><br>Ongoing: 39 hours per year; $3,631 per year | One Time: 18,720 hours; $1,742,734<br><br>Ongoing: 1,872 hours per year; $174,274 per year |
| Participate in Long-Term Regional Transmission Planning, which | 48 transmission providers with OATTs | 48 | One Time:<br>0 hours; $0 | One Time:<br>0 hours; $0 |

Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2022, issued April 25, 2023, http://bls.gov/oes/current/naics2_22.htm) and benefits (based on BLS data for September 2023; issued December 15, 2023, http://www.bls.gov/news.release/ecec.nr0.htm) and are Manager (Occupation Code 11-0000, $122.48/hour), Electrical Engineer (Occupation Code 17-2071, $89.04/hour), and File Clerk (Occupation Code 43-4071, $42.43/hour). The hourly cost for the reporting requirements ($105.76) is an average of the hourly cost (wages plus benefits) of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

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|---|---|---|---|---|
| includes creating and updating datasets, developing Long-Term Scenarios, evaluating the benefits of Long-Term Regional Transmission Facilities, and establishing criteria in consultation with Relevant State Entities and stakeholders to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation. | | | Ongoing:<br>4,995 hours per year; $465,010 per year | Ongoing:<br>239,760 hours per year; $22,320,457 per year |
| | 77 transmission providers without OATTs | 77 | One Time:<br>0 hours; $0<br><br>Ongoing:<br>202 hours per year; $18,805 per year | One Time:<br>0 hours; $0<br><br>Ongoing:<br>15,554 hours per year; $1,448,000 per year |
| **Total new burden for FERC 917 (due to Docket No. RM21-17-001)** | 48 transmission providers with OATTs | 48 | One Time: 1,113 hours; $103,614<br><br>Ongoing: 5,329 hours per year; $496,103 per year | One Time: 53,424 hours; $4,973,495<br><br>Ongoing: 255,792 hours per year; $23,812,956 per year |
| | 77 transmission providers without OATTs | 77 | One Time: 20 hours; $1,862<br><br>Ongoing: 262 hours per year; $24,391 per year | One Time: 1,540 hours; $143,366<br><br>Ongoing: 20,174 hours per year; $1,878,099 per year |
| | Totals for all 125 transmission providers | | | One Time: 54,964 hours; $5,116,861<br><br>Ongoing: 275,966 hours per year; $25,691,055 per year |

940. Order No. 1920 estimated the ongoing total burden and cost for the 48 transmission providers with OATTs to be 230,160 total hours per year and $21,426,693 per year. Similarly, Order No. 1920 estimated the ongoing total burden and cost for the 77 transmission providers without OATTs to be 20,020 total hours per year and $1,863,757 per year. Given the prior discussion regarding excluding corporate

commitments from Factor Category Seven and clarifications related to the potential for additional scenarios, additional consultation with Relevant State Entities, and posting or making available certain details of a selection decision on OASIS or other password-protected website, we estimate that these changes will result in an increase of burden hours. Therefore, we estimate that the ongoing total burden and cost, as revised herein, for the 48 transmission providers with OATTs to be 255,792 total hours per year and $23,812,956 per year. Similarly, we estimate that the ongoing total burden and cost, as revised herein, for the 77 transmission providers without OATTs to be 20,174 total hours per year and $1,878,099 per year. No other information collection requirements contained in Order No. 1920 are affected by this order on rehearing.

941. **Title:** Electric Transmission Facilities (FERC-917).

942. **Action:** Revision of collections of information in accordance with Docket No. RM21-17-001.

943. **OMB Control No.:** 1902-0233 (FERC-917)

944. **Respondents:** Transmission providers, including RTOs/ISOs.

945. **Frequency of Information Collection:** One time during Year 1. Occasional times during subsequent years, at least once every five years.

946. **Necessity of Information:** The modifications in this order on rehearing will correct deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

947. **Internal Review:** We have reviewed the requirements set forth in this order on rehearing that impose information collection burdens and have determined that such requirements are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

948. Interested persons may obtain information on the reporting requirements by contacting Kayla Williams, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 via email (DataClearance@ferc.gov) or telephone (202) 502-6468.

949. Comments concerning the collection of information and the associated burden estimates may also be sent to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following email address: oira_submission@omb.eop.gov. Comments submitted to OMB should refer to FERC-917 (OMB Control No. 1902-0233). Copies of the comments can be sent to the Commission (identified by Docket No. RM21-17-001 and the specific FERC collection number (FERC-917) electronically through https://www.ferc.gov. For those unable to file electronically, comment copies may be filed by USPS mail or by hand (including courier) delivery: Mail via U.S. Postal Service Only: Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington,

DC 20426. Or hand (including courier) delivery: Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

## XVI. Environmental Analysis

950. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[2304] The Commission has categorically excluded certain actions from this requirement including approval of actions under FPA sections 205 and 206 relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[2305] Because the final rule promulgated by Order No. 1920, and revised herein, falls within this categorical exclusion, preparation of an environmental assessment or an environmental impact statement is not required.

## XVII. Regulatory Flexibility Act

951. The Regulatory Flexibility Act of 1980 (RFA)[2306] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold

[2304] *Reguls. Implementing the Nat'l Env'l Pol'y Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[2305] 18 CFR 380.4(a)(15).

[2306] 5 U.S.C. 601-612.

for what constitutes a small business. Under SBA's size standards,[2307] RTOs/ISOs, transmission planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 950 employees (including the entity and its associates).[2308]

952. In Order No. 1920, the Commission, pursuant to RFA section 605(b), certified that the final rule would not have a significant economic impact on a substantial number of small entities.[2309] This order on rehearing does not disturb that conclusion. For the same reasons cited in Order No. 1920,[2310] the final rule, as revised herein, would not have a significant economic impact on a substantial number of small entities.

## XVIII. Document Availability

953. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov).

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[2307] 13 CFR 121.201.

[2308] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The SBA's regulations define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 950 employees. 13 CFR 121.201; *see* 5 U.S.C. 601(3) (citing section 3 of the Small Business Act, 15 U.S.C. 632).

[2309] Order No. 1920, 187 FERC ¶ 61,068 at P 1788.

[2310] *See id.*

954. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

955. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

## XIX. Effective Date

956. The changes to Order No. 1920 made in this order on rehearing and clarification are effective **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

**List of Subjects in 18 CFR Part 35**

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Christie is concurring in part with a separate statement attached.
Commissioner See is not participating.

( S E A L )

Debbie-Anne A. Reese,
Secretary.

NOTE: The following appendices will not appear in the Code of Federal Regulations.

## Appendix A: Abbreviated Names of Parties

| Abbreviation | Rehearing Party(ies) |
|---|---|
| Advanced Energy | Advanced Energy United |
| Alabama Commission | Alabama Public Service Commission |
| APPA | American Public Power Association |
| Arizona Commission | Arizona Corporation Commission |
| Cher Gilmore | Cher Gilmore |
| City of New Orleans Council | Council of the City of New Orleans |
| Clean Energy Associations | Advanced Energy United; American Clean Power Association; American Council on Renewable Energy; Solar Energy Industries Association |
| Clean Energy Buyers | Clean Energy Buyers Association |
| Competition Coalition | Electricity Transmission Competition Coalition; Resale Power Group of Iowa; LS Power Grid, LLC |
| CTC Global | CTC Global Corporation |
| Dairyland | Dairyland Power Cooperative |
| Designated Retail Regulators | Louisiana Public Service Commission; Mississippi Public Service Commission; Arkansas Public Service Commission; South Dakota Public Utilities Commission |
| Dominion | Dominion Energy Services, Inc. |
| E. Andrews | E. Andrews |
| East Kentucky | East Kentucky Power Cooperative, Inc. |
| EEI | Edison Electric Institute |
| Gary Andrews | Gary Andrews |
| Georgia Commission | Georgia Public Service Commission |
| Grid United | Grid United LLC |
| Harvard ELI | Harvard Electricity Law Initiative |
| Idaho Commission | Idaho Public Utilities Commission |
| Identified Consumer Advocates | Office of the Massachusetts Attorney General; Connecticut Office of Consumer Counsel; Maine Office of Public Advocate; Maryland Office of People's Counsel; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers |
| Illinois Commission | Illinois Commerce Commission |
| Indicated PJM TOs | American Electric Power Service Corporation on behalf of its affiliates, Appalachian Power Company, Indiana |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| | Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc.; Dayton Power and Light Company; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation on behalf of its affiliates Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Delmarva Power & Light Company, PECO Energy Company, and Potomac Electric Power Company; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, West Penn Power Company, Potomac Edison Company, Monongahela Power Company, Keystone Appalachian Transmission Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; UGI Utilities Inc. |
| Industrial Customers | American Forest & Paper Association; Coalition of MISO Transmission Customers; Industrial Energy Customers of America; PJM Industrial Customer Coalition |
| Invenergy | Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; Invenergy Transmission LLC |
| ITC | International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC |
| Large Public Power | Large Public Power Council |
| MISO TOs | Ameren Services Company, as agent for Union Electric |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| | Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; Wolverine Power Supply Cooperative, Inc. |
| Minnesota Commission | Minnesota Public Utilities Commission |
| Missouri Commission | Missouri Public Service Commission |
| Montana Commission | Montana Public Service Commission |
| NARUC | National Association of Regulatory Utility Commissioners |
| NESCOE | New England States Committee on Electricity |
| Northern Virginia | Northern Virginia Electric Cooperative, Inc. |
| NRECA | National Rural Electric Cooperative Association |
| Ohio Commission Federal Advocate | Public Utilities Commission of Ohio’s Office of the Federal Energy Advocate |
| Ohio Consumers | Office of the Ohio Consumers Council |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| Old Dominion | Old Dominion Electric Cooperative |
| Pennsylvania Commission | Pennsylvania Public Utility Commission |
| PIOs | Appalachian Voices; Energy Alabama; Environmental Defense Fund; Environmental Law & Policy Center; Natural Resources Defense Council; North Carolina Sustainable Energy Association; Sierra Club; South Carolina Coastal Conservation League; Southern Alliance for Clean Energy; Southern Renewable Energy Association; Sustainable FERC Project |
| PJM | PJM Interconnection, L.L.C. |
| PJM States | Organization of PJM States, Inc. |
| PJM Utilities | East Kentucky Power Cooperative, Inc.; Buckeye Power, Inc.; Old Dominion Electric Cooperative; Wabash Valley Power Association |
| SERTP Sponsors | Associated Electric Cooperative, Inc.; Dalton Utilities; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC; Georgia Transmission Corporation; Louisville Gas and Electric Company and Kentucky Utilities Company; Municipal Electric Authority of Georgia; PowerSouth Energy Cooperative; Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company; Tennessee Valley Authority |
| SPP | Southwest Power Pool, Inc. |
| State Regulatory Commissioners | Riley Allen (Commissioner, State of Vermont Public Utility Commission); Philip L. Bartlett II (Chair, Maine Public Utilities Commission); Kumar P. Barve (Commissioner, Maryland Public Service Commission); Eric Blank (Chairman, Colorado Public Utilities Commission); Alessandra Carreon (Commissioner, Michigan Public Service Commission); Michael T. Carrigan (Commissioner, Illinois Commerce Commission); David W. Danner (Chair, Washington Utilities and Transportation Commission); Megan Decker (Chair, Oregon Public Utilities Commission); Milt Doumit (Commissioner, Washington Utilities and Transportation Commission); Sarah Freeman (Commissioner, Indiana Utility Regulatory Commission); Andrew French (Chairperson, Kansas Corporation Commission); Marissa P. Gillett (Chairman, Connecticut |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| | Public Utilities Regulatory Authority); Hwikwon Ham (Commissioner, Minnesota Public Utilities Commission); Frederick H. Hoover (Chair, Maryland Public Service Commission); Darcie Houck (Commissioner, California Public Utilities Commission); Davante Lewis (Commissioner, Louisiana Public Service Commission); Ann McCabe (Commissioner, Illinois Commerce Commission); Valerie Means (Commissioner, Minnesota Public Utilities Commission); Stacey Paradis (Commissioner, Illinois Commerce Commission); Katherine Peretick (Commissioner, Michigan Public Service Commission); Les Perkins (Commissioner, Oregon Public Utilities Commission); Ann E. Rendahl (Commissioner, Washington Utilities and Transportation Commission); Alice Reynolds (President, California Public Utilities Commission); Michael T. Richard (Commissioner, Maryland Public Service Commission); Doug P. Scott (Chairman, Illinois Commerce Commission); Dan Scripps (Chair, Michigan Public Service Commission); Katie Sieben (Chair, Minnesota Public Utilities Commission); Bonnie A. Suchman (Commissioner, Maryland Public Service Commission); Joseph Sullivan (Vice Chair, Minnesota Public Utilities Commission); Letha Tawney (Commissioner, Oregon Public Utilities Commission); Emile C. Thompson (Chairman, District of Columbia Public Service Commission); Ted Trabue (Commissioner, District of Columbia Public Service Commission); John Tuma (Commissioner, Minnesota Public Utilities Commission) |
| Susann Rizzo | Susann Rizzo |
| TAPS | Transmission Access Policy Study Group |
| Undersigned States | Texas Attorney General; Alabama Attorney General; Arkansas Attorney General; Florida Attorney General; Georgia Attorney General; Idaho Attorney General; Iowa Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; North Dakota Attorney General; Oklahoma Attorney General; South Carolina Attorney General; South Dakota Attorney |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| | General; Tennessee Attorney General; Utah Attorney General |
| Utah Commission | Utah Public Service Commission |
| Vermont Commission | Vermont Public Utility Commission |
| Versant Power | Versant Power |
| Virginia Attorney General | Virginia Office of the Attorney General, Division of Consumer Counsel |
| Virginia and North Carolina Commissions | Virginia State Corporation Commission; North Carolina Utilities Commission |
| West Virginia Commission | Public Service Commission of West Virginia |
| WIRES | WIRES |
| Wyoming Commission | Wyoming Public Service Commission |

Appendix B: Pro Forma Open Access Transmission Tariff Attachment K

Note: Proposed deletions are in brackets and proposed additions are in italics.

ATTACHMENT K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open, and transparent local transmission planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open, and transparent local transmission planning process shall be provided as an attachment to the Transmission Provider's Tariff. The Transmission Provider's local transmission planning process shall provide stakeholders with meaningful opportunities to participate and provide feedback, and shall satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new transmission projects. The local transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The local transmission planning process also shall provide a mechanism for the recovery and allocation of transmission planning

costs consistent with Order No. 890. The description of the Transmission Provider's local transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the

needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order Nos. 1000 and 1920. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as established in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The description of the regional transmission planning process in the Tariff also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of "transmission planning costs" consistent with Order Nos. 890 and 1000.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region. The three meetings must occur before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's transmission planning models. The three stakeholder meetings for local transmission planning information are the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, and the three stakeholder meetings must meet the requirements in Order No. 1920.

As part of the regional transmission planning process, the Transmission Providers in each transmission planning region shall conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. As part of this Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall meet the requirements set forth in Order No. 1920, including: (1) identifying Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. 1920; (2) measuring the required seven benefits consistent with the requirements set forth in Order No. 1920;

(3) using the measured benefits to evaluate Long-Term Regional Transmission Facilities; and (4) using selection criteria consistent with the requirements set forth in Order No. 1920 that provide the opportunity for Transmission Providers to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address Long-Term Transmission Needs.

The process through which the Transmission Providers in each transmission planning region develop Long-Term Scenarios must comply with the following six transmission planning principles established in Order No. 890: coordination; openness; transparency; information exchange; comparability; and dispute resolution. The Transmission Providers in each transmission planning region shall outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios. The Transmission Providers in each transmission planning region shall also outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. *Transmission Providers shall consult with and consider the positions of the Relevant State Entities, and any other entity authorized by a Relevant State Entity as its representative, as to whether a specific state policy must be accounted for as a factor within each category, how to account for the specific state policy in the development of*

*Long-Term Scenarios, and how to adjust the treatment of the specific state policy across Long-Term Scenarios. When requested by Relevant State Entities in a transmission planning region, Transmission Providers shall conduct a reasonable number of additional analyses or scenarios to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es). Transmission Providers shall not use any such additional analyses to identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities, or to meet the requirement that Transmission Providers estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities for purposes of selection. Transmission Providers also shall not condition the selection of a Long-Term Regional Transmission Facility on the information provided in these additional analyses.*

The Transmission Providers in each transmission planning region shall include in their Tariffs a general description of how they will measure each of the seven required benefits used to evaluate Long-Term Regional Transmission Facilities. The Transmission Providers in each transmission planning region shall measure and use the seven benefits, as described in Order No. 1920, in Long-Term Regional Transmission Planning.

As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall include in their Tariffs an evaluation process, including selection criteria, that: (1) is transparent and not unduly discriminatory; (2) aims to ensure that more efficient or cost-effective transmission

facilities are selected in the regional transmission plan for purposes of cost allocation; (3) seeks to maximize benefits accounting for costs over time without over-building transmission facilities; and (4) otherwise satisfies the requirements set forth in Order No. 1920. *Once Transmission Providers make a selection decision ,and, if a State Agreement Process is used, once a cost allocation method is agreed upon, Transmission Providers shall make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how the estimated costs of a Long-Term Regional Transmission Facility will be allocated, by zone, and a quantification of the Long-Term Regional Transmission Facility's estimated benefits as imputed to each zone, as such benefits can be reasonably estimated.*

The Transmission Providers in each transmission planning region shall include in their Tariffs one or more Long-Term Regional Transmission Cost Allocation Methods, which is an ex ante regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation and that complies with the requirements set forth in Order No. 1920. The Transmission Providers in each transmission planning region may also, subject to (1) the agreement of Relevant State Entities and (2) Commission acceptance, include in their Tariffs a State Agreement Process. A State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation.

The Tariff must describe how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the *T*[t]ransmission *P*[p]rovider; and the circumstances under which, or the information necessary for, a *T*[t]ransmission *P*[p]rovider to file or to consider filing the agreed cost allocation.

*Transmission Providers shall include in their Tariffs a description of how they will consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the Transmission Provider to amend that method or process. For a consultation initiated by the Transmission Providers, Transmission Providers shall document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment. For a consultation initiated by Relevant State Entities, if the Transmission Providers choose not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) preferred by Relevant State Entities during the required consultation, Transmission Providers shall document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.*

As part of evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities, the Transmission Providers in each transmission planning

region shall consider in all of their regional transmission planning and cost allocation processes whether selecting transmission facilities that incorporate the following technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies: dynamic line ratings, as defined in 18 CFR § 35.28(b)(14), advanced power flow control devices, advanced conductors, and/or transmission switching. Specifically, such consideration must include both: (1) whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching as part of any potential regional transmission facility would be more efficient or cost-effective. Transmission *P*[p]roviders must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of Order No. 1920.

The Transmission Providers in each transmission planning region shall evaluate for potential selection in the regional transmission plan for purposes of cost allocation

regional transmission facilities that address interconnection-related transmission needs originally identified through the generator interconnection process. This requirement applies in the existing Order No. 1000 regional transmission planning processes. The Transmission Providers must modify their Tariffs to include these requirements. The interconnection-related transmission needs that Transmission Providers must evaluate in the existing Order No. 1000 regional transmission planning process are those for which:

(1) Transmission Providers in the transmission planning region have identified the relevant interconnection-related transmission need in interconnection studies in at least two interconnection queue cycles *(or in at least two individual interconnection studies for Transmission Providers that use a first-come, first-served serial generator interconnection process)* [during the preceding five years (looking back from the effective date of the accepted tariff provisions proposed to comply with this reform in Order No. 1920, and the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions)];

(2) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need has a voltage of at least 200 kV and an estimated cost of at least $30 million;

(3) [the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need is not currently planned to be developed because] the

interconnection request[(]s[)] that led to the identification of the interconnection-related transmission need *in two or more interconnection queue cycles (or two individual interconnection studies if the Transmission Provider uses a first-come, first-served serial generator interconnection process) have* [ has ]been withdrawn *and no more than five calendar years have passed between the date of an earlier interconnection request withdrawal and the date of a later interconnection request withdrawal*;[ and]

(4) the Transmission Providers have not identified a different interconnection-related Network Upgrade to meet the relevant interconnection-related transmission need in an executed Generator Interconnection Agreement or in a Generator Interconnection Agreement that the interconnection customer requested that the Transmission Provider file unexecuted with the Commission[.]*; and*

*(5) The interconnection request withdrawals associated with the repeatedly identified interconnection-related transmission need occurred no earlier than seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. The initial evaluation should occur in the first Order No. 1000 regional transmission planning and cost allocation cycle to occur after the effective date of the tariff revisions implementing this reform. The Transmission Provider need not evaluate an interconnection-related transmission need that has been evaluated in a previous Order No. 1000 regional transmission planning and cost*

*allocation cycle.*

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the regional transmission planning process and seek regional cost allocation;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the regional transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources; and

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include cost allocation methods that satisfy the requirements set forth in Order Nos. 1000 and 1920.

Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above a voltage threshold not to exceed 200 kV that an

individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs, as discussed in Order No. 1920. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. 1920. The Transmission Providers in each transmission planning region shall include in their Tariffs a cost allocation method for right-sized replacement transmission facilities that are selected in the regional transmission plan for purposes of cost allocation.

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans (including information regarding the Long-Term Transmission Needs and potential transmission facilities to meet those needs) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are

proposed to be located in both transmission planning regions, including those that may be more efficient or cost-effective transmission solutions to Long-Term Transmission Needs;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process, including:

(a) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings;

(b) any interregional transmission facilities proposed or identified in response to the Long-Term Transmission Needs;

(c) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning;

(d) the results of any cost-benefit evaluation of such interregional transmission facilities, with results including both any overall benefits identified, as well as any benefits particular to each transmission planning region; and

(e) the interregional transmission facilities, if any, selected in the regional transmission plan for purposes of cost allocation to meet Long-Term Transmission Needs.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new

interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation — Docket No. RM21-17-001

(Issued November 21, 2024)

CHRISTIE, Commissioner, *concurring in part*:

1. Today's order makes major changes to Order No. 1920. I am deeply grateful to my colleagues for their willingness to negotiate in good faith and ultimately to agree to these changes.

2. Order No. 1920 was based on purported authority derived from section 206 of the Federal Power Act (FPA).[1] Section 206 essentially requires that two prongs must be satisfied: First, the complainant, here the Commission, bears the burden to prove that existing rates – in this case, the transmission planning procedures of every transmission provider in the country, both Regional Transmission Organization (RTO)/Independent System Operator (ISO) and non-RTO/ISO – are unjust, unreasonable and/or unduly discriminatory or preferential. If the first prong (burden of proof) is met, in the second prong, the Commission must establish a just and reasonable replacement rate.[2] I concur with this order solely as to specific changes made in Order No. 1920-A to the replacement rate established in Order No. 1920.[3]

3. In my dissent to Order No. 1920, I made it clear that one of my major areas of disagreement was that it failed to fulfill the promise of a necessary and appropriate role for the states that was established in the Notice of Proposed Rulemaking (NOPR) that

[1] 16 U.S.C. § 824e.

[2] *Id.* ("Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, *the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order*. . . ." (emphasis added)).

[3] The specific changes which I support and to which I concur are described in the Appendix to this statement.

preceded Order No. 1920.[4] This promised state role was the primary reason I voted for the NOPR. As I have said repeatedly, state utility regulators are the first line of defense for their consumers and must have the authority to protect their consumers from unwarranted or excessive transmission costs, which are the fastest rising part of most consumers' monthly power bills and are reaching ever more burdensome levels.[5] The changes made today in Order No. 1920-A to the replacement rate set by Order No. 1920 go a *long* way towards restoring the state role to what the NOPR promised, and I am pleased to support these changes. Among them are the following positive and fundamental changes:

4. *Submission of State-Agreed Alternative*. In contrast to Order No. 1920, Order No. 1920-A requires that, if the states in a region agree to a cost allocation proposal, the transmission provider *must* include that agreement in its compliance filing. Furthermore, the Commission can choose the state agreement over the transmission provider's proposal.[6]

5. *Pre-Amendment State Consultation*. In addition, states *must* be consulted before the transmission provider considers any future changes to the cost allocation method or state agreement processes or if the states seek to amend the cost allocation method or state agreement processes.[7]

6. *Cost Allocation Flexibility*. In contrast to Order No. 1920, states are given far more flexibility to develop and agree to cost allocation processes and *ex ante* formulae that will suit their needs in diverse multistate regions such as PJM Interconnection, L.L.C. (PJM), Midcontinent Independent System Operator, Inc., and the Southeastern Regional Transmission Planning region. For example, states in PJM will now have explicit assurance that the PJM State Agreement Approach, in use for more than a decade, is preserved as an option for allocating to the sponsoring states the costs of public

[4] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, NOPR, 179 FERC ¶ 61,028 (2022) (Christie, Comm'r, concurring at PP 5, 11, 14).

[5] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024) (Christie, Comm'r, dissenting at P 15 & nn.49-54).

[6] *See* Appendix at P 1.

[7] *Id.* P 2.

policy-driven projects, such as New Jersey's offshore wind and others that would not be selected for regional cost allocation.[8]

7. *State Input on Factors*. As part of the planning process, transmission providers must consult with the states before running the scenarios required by Order No. 1920 and must consider the views of the states as to how to account for and weigh the factors related to, or derived from, state public policies.[9]

8. *State Input on Baseline Scenarios*. Order No. 1920-A also clarifies that, for purposes of cost allocation, states in PJM and other diverse multistate regions can now choose a new *ex ante* process that will enable the states to request that the transmission provider run additional scenarios, including a baseline scenario that contains only optimal reliability or economic projects and excludes public policy-driven projects, so that states can compare the costs of the baseline scenario versus the larger, multi-driver scenarios that include public policy-driven projects. Most importantly, states can agree that the difference in costs between the baseline scenario and the larger, multi-driver scenarios that include projects derived from state policies or other policy goals will be allocated to the states whose policies are the source of the added costs and will not be regionally cost allocated.[10]

9. *Removal of Corporate Power Preferences and Cost-Shifting*. The requirement in Order No. 1920 that large corporate power-purchasing preferences must be a factor in planning long-term scenarios is explicitly removed.[11] That was one of the most unconscionable, special-interest driven features of Order No. 1920, directing transmission providers to plan hundreds of billions of dollars of transmission projects to subsidize the power-purchasing preferences of huge multinational corporations and shifting the costs to residential and small-business consumers already struggling to pay their monthly power bills.

10. *New Required Transparency*. Order No. 1920-A also emphasizes transparency and clarifies that the purported benefits of one or more states' public policies are clearly identified and quantified. This will enable states to determine whether they are being

[8] *Id.* at P 7.

[9] *Id.* P 4.

[10] *Id.* PP 3, 8-11.

[11] *Id.* P 6.

charged for other states' public policies, which benefits they are paying for, and how much.[12]

11. Collectively, these changes give the states a much bigger toolbox containing far more effective tools they can use to protect their consumers and the interests of their states. I urge state regulators to use them aggressively. Further, let me emphasize that, if the process of compliance – always complicated and challenging even with rulemakings of far smaller size and less complexity than this one – demonstrates that state flexibility and authority remain materially insufficient, further action by the Commission may become necessary.

12. And on the issue of compliance, I would add that the broad purpose of these changes is to allow the states sufficient flexibility and authority to protect their consumers from paying unfair or unnecessary costs. *That purpose should and must inform the compliance process.*

13. For these reasons, I respectfully concur to these changes established in Order No. 1920-A that are listed specifically in the Appendix. Again, I express my deep appreciation to my colleagues for their willingness to engage in good-faith negotiations leading to these important changes to the replacement rate.

For these reasons I respectfully concur in part.

_____
Mark C. Christie
Commissioner

[12] *Id.* P 10.

## Appendix – Major Changes Incorporated in Order No. 1920-A

1. **Require transmission providers to include in their filings state agreements on cost allocation, with enough detail so that any separate proposals can be considered and enable the Commission to adopt the states' agreement on compliance.**

The order directs transmission providers to include in the transmittal of their compliance filings any Long-Term Regional Transmission Cost Allocation Method(s), and/or State Agreement Process(es) agreed to by Relevant State Entities, during the Engagement Period. The order also clarifies that transmission providers must include such cost allocation methods and/or State Agreement Processes in the transmittal of their compliance filings even when transmission providers propose on compliance a separate cost allocation method and/or declined to propose a State Agreement Process.

As part of this requirement, the order clarifies that transmission providers must include any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon cost allocation method and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing. However, the order clarifies that transmission providers are not required to separately characterize Relevant State Entities' agreement or independently justify Relevant State Entities' preferred cost allocation.

When acting under FPA section 206, the Commission's statutory burden is to establish a just and reasonable and not unduly discriminatory replacement rate that is supported by substantial evidence and is the product of reasoned decision making. In satisfying this burden with respect to cost allocation, it is not the case that the Commission necessarily must adopt the transmission provider's proposal if that proposal complies with the final rule's requirements; rather, the Commission need only weigh competing views (if they exist), select an approach with adequate support in the record, and then intelligibly explain the reasons for its choice.

To be clear, this means that the Commission will consider the entire record—including the Relevant State Entities' agreed-upon cost allocation and the transmission provider's proposal. Specifically, when the Commission reviews transmission providers' compliance filings, the Commission is not required to accept a cost allocation proposal from a transmission provider simply because it may comply with Order No. 1920. Instead, the Commission may accept any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920.

2. **Require transmission providers to revise their OATTs to add a requirement that they consult with Relevant State Entities before making a future filing under FPA section 205 to revise the Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process(es) that is on file.**

The order requires that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities prior to amending the *ex ante* Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process(es) agreed to by Relevant State Entities, or if Relevant State Entities seek to amend that method or process. The order requires transmission providers to document publicly on their website the results of that consultation prior to submitting their amendment. In addition, transmission providers must describe their reasoning for not using the results of the consultation with the Relevant State Entities. As an example, a jumpball framework, such as exists in MISO, SPP, and ISO-NE, could satisfy these requirements.

3. **If Relevant State Entities request additional scenarios to inform their consideration of cost allocation methods, transmission providers shall develop those additional scenarios.**

The order clarifies that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the development of Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es). The order further clarifies that, when developing these additional scenarios used to inform cost allocation, transmission providers have the flexibility to depart from Order No. 1920's requirements related to the development of Long-Term Scenarios. For example, transmission providers may develop scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. The order further clarifies that, if the Relevant State Entities wish for the transmission provider to develop a reasonable number of additional scenarios for cost allocation, then the transmission providers will develop these scenarios.

4. **Clarify that, while transmission providers have discretion over how to consider the effects of factors, transmission providers must consult with Relevant State Entities regarding factors related to state public policies.**

The order clarifies that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to state public policies in transmission planning assumptions. Specifically, the transmission provider shall consult with Relevant State Entities as to how to run the Long-Term

Scenarios mandated by the final rule, as they may incorporate planning for state laws, policies, and regulations, including assumptions of transmission needs that may be attributable to, or derived from, state or local policies, such as assumptions about changing generation resources.

**5. Allow states six additional months for the engagement period, upon request.**

The order clarifies that, if Relevant State Entities, consistent with their chosen method to reach agreement, request additional time to complete cost allocation discussions, the Commission will extend the Engagement Period for up to an additional six months. The order finds that such an extension is warranted in that circumstance to ensure that Relevant State Entities have sufficient time to engage in fulsome discussions. The order also clarifies that the Commission will extend the relevant compliance deadlines, as appropriate, to accommodate an extension to the Engagement Period.

**6. Exclude corporate commitments from Factor Category Seven.**

The order eliminates the requirement for transmission providers to incorporate corporate commitments in Factor Category Seven when developing Long-Term Scenarios. The order finds that requiring transmission providers to consider corporate commitments when developing Long-Term Scenarios may introduce the risk of one class of transmission users cross-subsidizing another class of transmission users.

**7. Expressly permit continued use of both new and/or existing state agreement approaches and similar voluntary measures.**

The order clarifies that Order No. 1920 does not require reapproval of PJM's State Agreement Approach. The order clarifies that the Commission interprets PJM's State Agreement Approach to be supplemental to PJM's existing regional transmission cost allocation method. As a result, it is not in any way affected by the final rule. The order further clarifies (see #1 above) that, in their compliance filings, transmission providers shall include any State Agreement Process(es) agreed to by Relevant State Entities.

**8. Transmission providers will allocate the costs of a Long-Term Regional Transmission Facility commensurate to its benefits.**

The order clarifies that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion to those benefits. One potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation. Under this potential cost allocation method, these costs and benefits could be identified based on one or more additional

scenarios run by the transmission planner for the purposes of informing cost allocation, e.g., scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. For example, the cost allocation method agreed to by the Relevant State Entities may allocate those incremental costs to states with those applicable laws, policies, and regulations.

**9. Clarify that states and/or transmission providers may define additional benefits to those enumerated in Order No. 1920.**

Further, the order clarifies that costs borne by ratepayers must be roughly commensurate with benefits received. Transmission providers can consider additional benefits for cost allocation purposes, including as agreed to by Relevant State Entities and described elsewhere in this rule, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

**10. Clarify that, for a selected project or tranche of projects, transmission providers shall, for each pricing zone, quantify the benefits and costs associated with such project or tranche.**

The order clarifies that, for each selected project or tranche of projects, each transmission provider is required to make publicly available, on OASIS or other password-protected website, a breakdown of the allocated costs, by transmission pricing zone, and a quantification of the benefits imputed to each zone, as such benefits can be reasonably estimated.

**11. Include, as an example of an approach that could be proposed to comply with Order No. 1920, the below *ex ante* cost allocation method language for Relevant State Entities. The inclusion of this example does not foreclose states from agreeing to other cost allocation approaches, each of which shall be evaluated on its own merits.**

At the request of the Relevant State Entities in a multistate region, the following *ex ante* method for cost allocation may be proposed. In providing this example, the order is not foreclosing other approaches for allocating the costs of Long-Term Regional Transmission Facilities on either an *ex ante* or project-specific basis. Nor is the order suggesting that cost allocation methodologies must adopt a similar approach to this framework in order to comply with the requirements of this final rule:

(1) For purposes of cost allocation, the transmission providers shall run a scenario that otherwise complies with the Long-Term Regional Transmission Planning requirements of Order No. 1920 but does not include state laws, policies, and regulations and quantify the costs of the projects that would be selected from this

scenario.

(2) The costs identified in (1) could be cost allocated according to an alternative *ex ante* formula filed by the transmission owners for the region.

(3) The amount representing the cost difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) shall be allocated as follows:

a. The transmission provider shall identify by state the specific state laws, policies, and regulations that were used to plan and select the facilities and shall quantify *by state* the specific costs of such facilities.

b. The costs identified in 3(a) shall be allocated solely to the state or states that are the sources of the policies used in planning and selection. The total difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) would be fully accounted for using this method of allocating costs among the states. The costs by zone *within* a state (Intrastate Costs) would be developed and filed by the applicable Transmission Owner(s).

Document Content(s)

RM21-17-001.docx.....1

191 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM21-17-003; Order No. 1920-B]

# Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

(Issued April 11, 2025)

**AGENCY**: Federal Energy Regulatory Commission.

**ACTION**: Order on rehearing and clarification

**SUMMARY**: In this order, the Federal Energy Regulatory Commission addresses arguments raised on rehearing, grants clarification, in part, and denies clarification, in part, of Order No. 1920-A, which addressed arguments raised on rehearing of, set aside, in part, and clarified Order No. 1920. Order No. 1920 required transmission providers, *inter alia*, to conduct Long-Term Regional Transmission Planning to ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

**DATES**: The effective date of the document published on December 6, 2024 (89 FR 97,174), is confirmed: January 6, 2025.

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**SUPPLEMENTARY INFORMATION**:

191 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
Willie L. Phillips, David Rosner,
and Judy W. Chang.

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation — Docket No. RM21-17-003

# ORDER NO. 1920-B

# ORDER ON REHEARING AND CLARIFICATION

(Issued April 11, 2025)

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## I. Introduction

1. In Order No. 1920,[1] the Federal Energy Regulatory Commission (Commission) revised the *pro forma* Open Access Transmission Tariff (OATT) to adopt reforms to its existing electric transmission planning and cost allocation requirements pursuant to section 206 of the Federal Power Act (FPA).[2] The Commission found that existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because, *inter alia*, the Commission's existing transmission planning and cost allocation requirements do not require transmission providers[3] to: (1) perform a sufficiently long-term assessment of transmission needs that

[1] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068, *order on reh'g & clarification*, Order No. 1920-A, 89 FR 97174 (Dec. 6, 2024), 189 FERC ¶ 61,126 (2024).

[2] 16 U.S.C. 824e.

[3] FPA Section 201(e), 16 U.S.C. 824(e), defines "public utility" to mean "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." As stated in the Order No. 888 *pro forma* OATT, "transmission provider" is a "public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048

identifies Long-Term Transmission Needs;[4] (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[5] Building on Order Nos. 890[6] and 1000,[7] Order No. 1920 addresses these deficiencies by establishing requirements to ensure that

(cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N. Y. v. FERC*, 535 U.S. 1 (2002); *pro forma* OATT section I.1 (Definitions). The term "transmission provider" includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO).

[4] For purposes of Order No. 1920, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in Order Nos. 1920 and 1920-A, running scenarios and considering the enumerated categories of factors. Order No. 1920, 187 FERC ¶ 61,068 at P 299; Order No. 1920-A, 189 FERC ¶ 61,126 at P 20 n.16.

[5] Order No. 1920, 187 FERC ¶ 61,068 at P 1.

[6] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119 (2007), *order on reh'g,* Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[7] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (*South Carolina*).

Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential, including, *inter alia*, a requirement that transmission providers in each transmission planning region participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning,[8] which will ensure the identification, evaluation, and selection of more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs, as well as the just and reasonable allocation of the costs of those facilities.[9]

2. In Order No. 1920-A, the Commission largely sustained the reforms adopted in Order No. 1920 while refining and improving those reforms to address concerns raised in response to Order No. 1920 and to ensure that states have a robust role in Long-Term Regional Transmission Planning and in the cost allocation processes established in the final rule. Specifically, and as relevant here, the Commission set aside, in part, and clarified, in part, Order No. 1920 to provide that: (1) transmission providers may not plan for the needs of a non-jurisdictional transmission provider if that non-jurisdictional transmission provider has not enrolled in the transmission planning region and thereby

[8] For purposes of Order No. 1920, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. Order No. 1920, 187 FERC ¶ 61,068 at PP 38, 250-252; Order No. 1920-A, 189 FERC ¶ 61,126 at P 21 n.17.

[9] Order No. 1920, 187 FERC ¶ 61,068 at PP 1-2.

has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities;[10] (2) when Relevant State Entities[11] agree on a Long-Term Regional Transmission Cost Allocation Method(s)[12] and/or State Agreement Process[13] resulting from the Engagement Period,[14] transmission providers must include that

[10] Order No. 1920-A, 189 FERC ¶ 61,126 at P 323. For purposes of Order No. 1920, a Long-Term Regional Transmission Facility is a regional transmission facility, as defined in Order No. 1000, that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs. Order No. 1920, 187 FERC ¶ 61,068 at PP 41, 250; Order No. 1920-A, 189 FERC ¶ 61,126 at P 21 n.18.

[11] For purposes of Order No. 1920, a Relevant State Entity is any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state. Order No. 1920, 187 FERC ¶ 61,068 at PP 44, 1355; Order No. 1920-A, 189 FERC ¶ 61,126 at P 23 & n.23.

[12] For purposes of Order No. 1920, a Long-Term Regional Transmission Cost Allocation Method is an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. Order No. 1920, 187 FERC ¶ 61,068 at P 1291; Order No. 1920-A, 189 FERC ¶ 61,126 at P 612 n.1539.

[13] For purposes of Order No. 1920, a State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected in the regional transmission plan for purposes of cost allocation. Order No. 1920, 187 FERC ¶ 61,068 at P 45; Order No. 1920-A, 189 FERC ¶ 61,126 at P 24 n.28.

[14] For purposes of Order No. 1920, an Engagement Period is a six-month time period during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional

method(s) and/or process in the transmittal or as an attachment to their Order No. 1920 regional transmission planning and cost allocation compliance filings, along with any information that Relevant State Entities provide to transmission providers regarding the state negotiations during the Engagement Period, even if transmission providers propose a different Long-Term Regional Transmission Cost Allocation Method or do not propose to adopt a State Agreement Process;[15] (3) the Commission will consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate in Order No. 1920 regional transmission planning and cost allocation compliance proceedings;[16] and (4) transmission providers must consult with Relevant State Entities prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process or, if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission providers to amend that method or process.[17] As further relevant here, the Commission disagreed with certain arguments raised on rehearing of Order No. 1920 and continued to: (1) find that the Commission

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Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities. Order No. 1920, 187 FERC ¶ 61,068 at PP 5, 1354; Order No. 1920-A, 189 FERC ¶ 61,126 at P 24.

[15] Order No. 1920-A, 189 FERC ¶ 61,126 at P 651.

[16] *Id.* P 659.

[17] *Id.* P 691.

made adequate findings and marshalled sufficient evidence under the first prong of FPA section 206 to establish that existing Commission-jurisdictional regional transmission planning and cost allocation processes are unjust and unreasonable;[18] and (2) define Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.[19]

3. Seven petitioners have sought further rehearing and clarification of the Commission's determinations in Order No. 1920-A,[20] and the Commission received two additional filings.[21] Pursuant to *Allegheny Defense Project v. FERC*,[22] the rehearing

[18] *See id.* PP 72-86.

[19] *See id.* P 685.

[20] Appendix A includes a list of petitioners submitting requests for rehearing and/or clarification of Order No. 1920-A.

[21] On February 5, 2025, NRECA sent a letter to Chairman Mark Christie addressing Order No. 1920-A. On February 12, 2025, Developers Advocating Transmission Advancements submitted a late-filed pleading and white paper in response to the 2021 Advanced Notice of Proposed Rulemaking. To the extent that they intend to seek rehearing, these pleadings are untimely and we therefore reject them. 16 U.S.C. 825*l*(a); 18 CFR 385.713(b) (2024). They also do not include a separate section entitled "Statement of Issues" listing each issue presented to the Commission in a separately enumerated paragraph, as required by Rule 713(c)(2) of the Commission's Rules of Practice and Procedure. 18 CFR 385.713(c)(2). Below, we address NRECA's rehearing request, which raised similar issues to those NRECA raised in its letter. *See infra* Definition of Relevant State Entities section.

[22] 964 F.3d 1 (D.C. Cir. 2020) (en banc).

requests filed in this proceeding may be deemed denied by operation of law. However, as permitted by FPA section 313(a),[23] we are modifying the discussion in Order No. 1920-A and continue to reach the same result in this proceeding, as discussed below.[24] That is, in this order, we do not change the outcome of Order No. 1920-A.[25] This order also does not amend the Commission's regulations or the provisions of Attachment K to the *pro forma* OATT.

4. We also grant, in part, and deny, in part, the requests for clarification. Specifically, we clarify one aspect of the Commission's discussion in Order No. 1920-A to explain that, consistent with Order No. 1000, transmission providers are not required to plan for the Long-Term Transmission Needs of unenrolled non-jurisdictional transmission providers, but voluntary arrangements for regional transmission planning and cost allocation that comply with the FPA and the Commission's cost causation precedent are not prohibited.[26] In addition, we sustain the requirement in Order

[23] 16 U.S.C. 825*l*(a) ("Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

[24] *Allegheny Def. Project*, 964 F.3d at 16-17.

[25] *See Smith Lake Improvement & Stakeholders Ass'n v. FERC*, 809 F.3d 55, 56-57 (D.C. Cir. 2015).

[26] *See* Order No. 1920-A, 189 FERC ¶ 61,068 at P 323; *infra* Planning for the Long-Term Transmission Needs of Unenrolled Non-Jurisdictional Transmission Providers section.

No. 1920-A that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process resulting from the Engagement Period, and associated information provided to transmission providers regarding the state negotiations during the Engagement Period, in transmission providers' transmittal or as an attachment to their Order No. 1920 regional transmission planning and cost allocation compliance filings.[27] We further sustain the requirement that transmission providers consult with Relevant State Entities: (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process; or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.[28] We are not persuaded, however, by NRECA's request to expand the definition of Relevant State Entity to include any entity that establishes or regulates electric rates under state law.[29] Finally, we reject as procedurally barred Indicated PJM TOs' and SPP TOs' arguments that the Commission's findings under the first prong of FPA section 206 were insufficient to support its exercise of authority in Order No. 1920.[30]

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[27] Order No. 1920-A, 189 FERC ¶ 61,126 at PP 651, 655; *infra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods section.

[28] Order No. 1920-A, 189 FERC ¶ 61,126 at P 691; *infra* Consultation with Relevant State Entities After the Engagement Period section.

[29] Order No. 1920-A, 189 FERC ¶ 61,126 at P 701; *infra* Definition of Relevant State Entities section.

[30] Order No. 1920-A, 189 FERC ¶ 61,126 at PP 72-86; *infra* Other Cost Allocation Issues section.

5. We continue to find that these reforms, as refined and improved in Order No. 1920-A, ensure that transmission providers will conduct sufficiently long-term, forward looking, and comprehensive transmission planning and cost allocation processes to meet the demands of the modern transmission grid, while facilitating meaningful participation by the states, consistent with the jurisdictional boundaries delineated in the FPA.

## II. Long-Term Regional Transmission Planning

### A. Planning for the Long-Term Transmission Needs of Unenrolled Non-Jurisdictional Transmission Providers

#### 1. Order Nos. 1920 and 1920-A

6. In Order No. 1920, the Commission required transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.[31] To identify Long-Term Transmission Needs and to identify and evaluate transmission facilities that meet such needs, transmission

[31] Order No. 1920, 187 FERC ¶ 61,068 at P 224; *see also* Order No. 1920-A, 189 FERC ¶ 61,126 at P 138.

providers must develop a set of at least three plausible and diverse Long-Term Scenarios,[32] each of which must: (1) incorporate seven specific categories of factors that represent known determinants of Long-Term Transmission Needs; and (2) account for factors within each such category that the transmission provider determines are likely to affect Long-Term Transmission Needs.[33] Factor Category Three comprises state-approved integrated resource plans and expected supply obligations for load-serving entities.[34]

7. In Order No. 1920-A, the Commission clarified that, for purposes of complying with the requirements of Order No. 1920, transmission providers must plan for the needs of non-jurisdictional entities that are among the transmission providers' transmission customers as they would plan for the needs of any other transmission customer. For example, each Long-Term Scenario must account for and be consistent with factors within Factor Category Three once transmission providers in a transmission planning region have determined that such factors are likely to affect Long-Term Transmission Needs. This includes any non-jurisdictional transmission customer's resource planning

[32] Order No. 1920 defines Long-Term Scenarios as scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs. Order No. 1920, 187 FERC ¶ 61,068 at PP 40, 302.

[33] *Id*. PP 298, 409, 415.

[34] *Id*. P 447; *see also* Order No. 1920-A, 189 FERC ¶ 61,126 at PP 139, 263, 279.

and procurement processes that have been approved by that entity's respective governing authority.[35]

8. The Commission further clarified in Order No. 1920-A that "transmission providers may *not* plan for the needs of a non-jurisdictional utility transmission provider if that non-jurisdictional transmission provider has not enrolled in the transmission planning region and thereby has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities."[36] The Commission stated that, if transmission providers were to plan for and consider non-jurisdictional transmission providers' Long-Term Transmission Needs without a way to ensure the non-jurisdictional transmission provider contributes to the costs of the resulting Long-Term Regional Transmission Facilities, the resulting cost allocation could violate the cost causation principle and result in free-ridership.[37]

### 2. Rehearing Requests

9. NRECA and WestConnect CTOs request rehearing and/or clarification of the statement in Order No. 1920-A that "transmission providers may *not* plan for the needs of

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[35] Order No. 1920-A, 189 FERC ¶ 61,126 at P 323 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 507, 510). The Commission issued this clarification in response to a request to clarify that the resource planning and procurement processes of non-jurisdictional transmission providers that have been approved by their respective governing authorities should be included in Factor Category Three. *Id.* P 315 (citing SERTP Sponsors June 12, 2024 Rehearing Request at 5).

[36] *Id.* P 323 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 276).

[37] *Id.* (citing *El Paso Elec. Co. v. FERC*, 76 F.4th 352, 363-66 (5th Cir. 2023) (*El Paso*)).

a non-jurisdictional utility transmission provider if that non-jurisdictional transmission provider has not enrolled in the transmission planning region and thereby has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities."[38] In particular, NRECA and WestConnect CTOs assert that this statement could be read to prohibit transmission providers from voluntarily agreeing to plan for the needs of unenrolled non-jurisdictional transmission providers.[39]

10. NRECA asks the Commission to clarify that Order No. 1920-A does not change the Commission's existing regulations and policy, and thus transmission providers in a transmission planning region continue to have the discretion to plan for the needs of a non-jurisdictional transmission provider that has not enrolled in the regional transmission planning process.[40] NRECA asserts that its requested interpretation of Order No. 1920-A is supported by the Commission's own citation to the language in Order No. 1000-A, stating that the regional transmission planning process is not required to plan for the

[38] NRECA Rehearing Request at 3 (quoting Order No. 1920-A, 189 FERC ¶ 61,126 at P 323); WestConnect CTOs Rehearing Request at 1 (same).

[39] NRECA Rehearing Request at 3, 17; WestConnect CTOs Rehearing Request at 1-5 (asserting that Order No. 1920-A, misinterpreting *El Paso*, establishes a prohibition on voluntary planning with unenrolled non-jurisdictional transmission providers).

[40] NRECA Rehearing Request at 3; *see also id.* at 16 ("NRECA requests that the Commission clarify that 'may *not* plan' means 'is not *required* to plan' rather than 'is not *permitted* to plan.'" (emphasis in original)).

transmission needs of a non-jurisdictional, unenrolled transmission provider.[41] NRECA states that the Commission has interpreted Order No. 1000-A as neither prohibiting nor compelling regional transmission planning processes from planning for the transmission needs of unenrolled non-jurisdictional transmission providers, i.e., non-jurisdictional transmission providers that have not agreed to accept any applicable cost allocation method for selected regional transmission facilities.[42]

11. NRECA also argues that its requested interpretation of Order No. 1920-A is consistent with the next sentence of Order No. 1920-A, which states that, "[i]f the transmission provider were to plan for and consider non-jurisdictional transmission providers' Long-Term Transmission Needs without a way to ensure the non-jurisdictional transmission provider contributes to the costs of the resulting Long-Term Regional Transmission Facilities, the resulting cost allocation could violate the cost causation principle and result in free-ridership."[43] NRECA asserts that this rationale supports Order No. 1000-A's statement that the public utility transmission providers in a transmission planning region are not compelled to plan for the transmission needs of an unenrolled non-jurisdictional transmission provider that has not agreed to accept any

[41] *Id.* at 16 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 323 n.914 (citing Order No. 1000-A, 139 FERC ¶ 61,132 at P 276)).

[42] *Id.* at 16, 17 (citing *Pub. Serv. Co. of Colo.*, 148 FERC ¶ 61,213 (2014), *order on reh'g*, 151 FERC ¶ 61,128 (2015), *vacated & remanded*, *El Paso Elec. Co. v. FERC*, 832 F.3d 495 (5th Cir. 2016)).

[43] *Id.* at 16 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 323).

applicable cost allocation method for selected regional transmission facilities, but does not justify prohibiting voluntary planning for such needs if transmission providers in a transmission planning region can ensure that they will not be required to subsidize transmission projects that benefit the unenrolled non-jurisdictional transmission providers.[44]

12. NRECA and WestConnect CTOs each argue that the court in *El Paso* did not hold that the FPA requires the Commission to prohibit transmission providers in a transmission planning region from voluntarily planning for unenrolled non-jurisdictional transmission providers' needs.[45] NRECA states that the *El Paso* court had no reason for such a holding in reviewing an Order No. 1000 regional compliance filing but simply quoted with approval the Commission's "'clear' statement" in Order No. 1000-A.[46] Thus, NRECA contends, Order No. 1000-A and *El Paso* allow transmission providers in a transmission planning region to agree to plan for the transmission needs of unenrolled non-jurisdictional transmission providers if they have assurance that the enrolled

[44] *Id.* at 16-17.

[45] *Id.* at 17 (citing *El Paso*, 76 F.4th at 363); WestConnect CTOs Rehearing Request at 4 (asserting that *El Paso* holds only that public utilities may not be required to plan for the transmission needs of unenrolled non-jurisdictional utilities that do not accept the allocation of costs related to regional transmission projects from which they benefit (citing *El Paso*, 76 F.4th at 362-63)).

[46] NRECA Rehearing Request at 17 (quoting *El Paso*, 76 F.4th at 363).

transmission providers will not be required to subsidize transmission projects that benefit the unenrolled non-jurisdictional transmission providers.[47]

13. WestConnect CTOs assert that the issue on which the transmission providers prevailed in *El Paso* was their objection to being forced to subsidize transmission projects from which unenrolled non-jurisdictional transmission providers who did not commit to the allocation of costs might nonetheless benefit. WestConnect CTOs assert that members of WestConnect believed that the risk of subsidization could be sufficiently minimized to allow their long history of beneficial coordinated transmission planning to continue without enrollment of the WestConnect unenrolled non-jurisdictional transmission providers.[48] WestConnect CTOs argue that, contrary to the Commission's statement in Order No. 1920-A, it is untrue that transmission providers cannot ensure that an unenrolled non-jurisdictional transmission provider contributes to the cost of a regional transmission project from which it benefits without enrolling in the transmission planning region.[49] WestConnect CTOs assert that prohibiting joint regional transmission planning is based on a false binary choice—that non-jurisdictional transmission providers are not required to enroll in a transmission planning region and can only participate if

[47] *Id.*

[48] WestConnect CTOs Rehearing Request at 6 (citing *Ariz. Pub. Serv. Co.*, 181 FERC ¶ 61,223, at P 14 (2022)).

[49] *Id.* at 5 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 323).

they enroll.[50] WestConnect CTOs represent that the WestConnect transmission planning region's transmission providers remain open to considering a modified coordinating transmission owner framework that provides them reasonable assurance that they will not have to subsidize their non-jurisdictional counterparts without requiring their enrollment.[51]

14. WestConnect CTOs further state that banning the possibility of voluntary arrangements for joint regional transmission planning with unenrolled non-jurisdictional transmission providers violates FPA section 202(a), under which the Commission is "affirmatively not only 'empowered,' but '*directed* to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy.'"[52]

15. WestConnect CTOs and NRECA argue that a ban on regional transmission planning by public utilities and unenrolled non-jurisdictional transmission providers would be an unacknowledged, unexplained, and hence arbitrary departure from Order No. 1000 precedent.[53] WestConnect CTOs argue that the Commission's

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[50] *Id.* at 6; *see also id.* at 9 n.17 (citing *Pub. Serv. Co. of Colo.*, WestConnect CTOs Request for Clarification, Docket No. ER13-75-014, et al., at n.2 (filed Nov. 18, 2024)).

[51] *Id.* at 5 (citing *Pub. Serv. Co. of Colo.*, WestConnect CTOs Request for Clarification, Docket No. ER13-75-014, et al. (filed Nov. 18, 2024)).

[52] *Id.* (quoting 16 U.S.C. 824a(a) (emphasis added)).

[53] *Id.* at 2-3, 6; NRECA Rehearing Request at 4-5, 18 (citing 5 U.S.C. § 706(2)(A) (other citations omitted)).

misinterpretation of *El Paso* is counterproductive to the Commission's professed goal of Order Nos. 1000 and 1920—to encourage and enhance regional transmission planning.[54]

16. WestConnect CTOs state that the Commission has noted that it "accepted the WestConnect public utility transmission providers' proposed participation framework [(i.e., the coordinating transmission owner framework)] under which non-public utility transmission providers could participate in WestConnect as either enrolled transmission owners or coordinating transmission owners."[55] WestConnect CTOs also state that the Commission expressly held that Order No. 1000 "does not preclude the enrolled public utility transmission providers in a transmission planning region from conducting transmission planning for unenrolled non-public utility transmission providers if the enrolled public utility transmission providers elect to do so."[56] WestConnect CTOs argue

[54] WestConnect CTOs Rehearing Request at 6; *see also id.* at 6-7 (asserting that, in Order No. 1000 compliance proceedings, WestConnect transmission providers explained that non-jurisdictional transmission providers' enrollment was not a prerequisite to their participation in regional transmission planning and would run contrary to the goals of Order No. 1000) ("It was precisely because of the presence of a large number of both public utility and non-jurisdictional utility transmission owners in the WestConnect region that the [j]urisdictional [u]tilities strove to create a compliance structure that would be superior to one in which non-jurisdictional utilities unwilling to subject themselves to Order No. 1000 cost allocation would be excluded from the region's planning process entirely." (quoting *Pub. Serv. Co. of Colo.*, Motion for Leave to Answer and Answer of the WestConnect Jurisdictional Utilities, Docket No. ER13-75-003 et al., at 13-14 (filed Nov. 8, 2013))).

[55] *Id.* at 7 (quoting *Pub. Serv. Co. of Colo.*, 189 FERC ¶ 61,028, at P 6 (2024) (WestConnect Remand Order), *order on reh'g*, 190 FERC ¶ 61,128 (2025) (Remand Rehearing Order)).

[56] *Id.* at 7-8 (quoting *Pub. Serv. Co. of Colo.*, 148 FERC ¶ 61,213 at P 55).

that this holding underpinned the development of WestConnect's existing coordinating transmission owner framework and was not challenged or addressed in *El Paso*. On the contrary, WestConnect CTOs argue, *El Paso* does not alter—and could not have altered—Order No. 1000's holdings, which were affirmed by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit).[57]

17. WestConnect CTOs argue that the Commission's prohibition on transmission providers planning for the needs of unenrolled non-jurisdictional transmission providers fails to acknowledge, explain, or consider WestConnect CTOs' substantial reliance interest in the Commission's prior approval of the coordinating transmission owner framework.[58]

18. WestConnect CTOs further note that, in Order No. 1000, the Commission required that the scope of a transmission planning region "be governed by the integrated nature of the regional power grid."[59] WestConnect CTOs allege that the Commission stated that without the participation of non-jurisdictional transmission providers interspersed throughout the WestConnect transmission planning region that make up half of its membership, WestConnect would be like "swiss cheese."[60] WestConnect CTOs state

[57] *Id.* at 8 (citing *South Carolina*, 762 F.3d 41).

[58] *Id.* (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Dep't of Homeland Sec. v. Regents of the Univ. of Cal.*, 591 U.S. 1, 30 (2020)).

[59] *Id.* (citing WestConnect Remand Order, 189 FERC ¶ 61,028 at P 23 & n.49).

[60] *Id.* at 8-9 (citing *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, at P 349 (2013), *order on reh'g*, 148 FERC ¶ 61,213, *order on reh'g*, 151 FERC ¶ 61,128, *vacated &*

that one of the reasons coordinating transmission owners supported WestConnect's coordinating transmission owner framework was the institutional difficulties non-jurisdictional transmission providers face in agreeing to enrollment rather than case-by-case acceptance of cost allocation for regional transmission projects.[61] WestConnect CTOs argue that Order No. 1920-A does not acknowledge or explain how transmission providers barred from joint regional transmission planning with unenrolled non-jurisdictional transmission providers can meet Order No. 1000's integration requirement in a transmission planning region like WestConnect.[62]

19. WestConnect CTOs state that while the Commission found in its order on remand from *El Paso* that WestConnect remains an integrated transmission planning region even without participation of coordinating transmission owners, the Commission does not incorporate or reference that finding in Order No. 1920-A.[63] Nevertheless, WestConnect CTOs object to the Commission's determination in its order on remand from *El Paso* regarding the continued integration of the WestConnect transmission planning region.[64]

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*remanded*, *El Paso Elec. Co. v. FERC*, 832 F.3d 495). The order that WestConnect CTOs cite does not contain this statement.

[61] *Id.* at 9.

[62] *Id.*

[63] *Id.* at 9 n.17 (citing WestConnect Remand Order, 189 FERC ¶ 61,028 at P 23).

[64] *Id.* (quoting *Pub. Serv. Co. of Colo.*, WestConnect CTOs Request for Clarification, Docket No. ER13-75-013, et al. (filed Nov. 18, 2024) (internal quotations omitted)).

20. WestConnect CTOs assert that the ban on use of a coordinating transmission owner framework would all but ensure the failure of regional transmission planning in WestConnect, contrary to the objectives of Order Nos. 1000 and 1920. WestConnect CTOs contend that the Commission's failure to acknowledge its departure from existing policy or explain how a mandatory enrollment requirement would be consistent with Order No. 1000's integration requirement was arbitrary.[65]

### 3. Commission Determination

21. We agree with rehearing petitioners that Order No. 1920-A does not modify the requirements of Order No. 1000 with respect to planning for the needs of unenrolled non-jurisdictional transmission providers.[66] Although Order No. 1000 does not require a coordinating transmission owner framework, Order No. 1000 and *El Paso* do not explicitly foreclose the possibility that a voluntary arrangement for regional transmission planning *and* cost allocation that includes unenrolled non-jurisdictional transmission providers could comply with the FPA's mandate for just and reasonable rates and the Commission's cost causation precedent.[67] Accordingly, we clarify the Commission's statement in Order No. 1920-A that transmission providers may *not* plan for the needs of a non-jurisdictional transmission provider if that non-jurisdictional transmission provider

[65] *Id.* at 9 (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 515).

[66] *See* NRECA Rehearing Request at 3, 17; WestConnect CTOs Rehearing Request at 8.

[67] *See* Remand Rehearing Order, 190 FERC ¶ 61,128 at P 28.

has not enrolled in the transmission planning region and thereby has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities.[68] Specifically, we agree with NRECA that transmission providers are not *required* to plan for the Long-Term Transmission Needs of unenrolled non-jurisdictional transmission providers.[69] In *El Paso*, the U.S. Court of Appeals for the Fifth Circuit held that the Commission's orders accepting WestConnect's coordinating transmission owner framework were incompatible with the FPA and with the application of the cost causation principle in Order No. 1000 because they permitted non-public utility transmission providers to cause transmission costs to be incurred through the WestConnect regional transmission planning process without bearing cost responsibility.[70] The Commission will evaluate any voluntary arrangement for regional transmission planning and cost allocation that includes unenrolled non-jurisdictional transmission providers if and when it comes before the Commission, and that is unaffected by Order No. 1920-A. We

[68] Order No. 1920-A, 189 FERC ¶ 61,068 at P 323. We find moot WestConnect CTOs' arguments that the relevant language in Order No. 1920-A violates the Commission's obligations under FPA section 202(a) and the objectives of Order No. 1000 as well as NRECA's argument that this language conflicts with other statements in Order No. 1920-A. *See* WestConnect CTOs Rehearing Request at 4-5, 9; NRECA Rehearing Request at 16-17. Our clarification of Order No. 1920-A in relevant part resolves these claims.

[69] *See* Order No. 1000-A, 139 FERC ¶ 61,132 at P 276 ("[T]he regional transmission planning process is not required to plan for the transmission needs of such a non-public utility transmission provider that has not made the choice to join a transmission planning region."); *see also El Paso*, 76 F.4th at 362-63 (quoting the same).

[70] *El Paso*, 76 F.4th at 365-66; *id*. at 363 (discussing cost causation concerns).

emphasize that any transmission provider proposing to include unenrolled non-jurisdictional transmission providers in regional transmission planning and cost allocation, including Long-Term Regional Transmission Planning, must demonstrate that its proposed arrangement will not result in free ridership in violation of the cost causation principle and otherwise complies with the requirements of Order No. 1000, Order No. 1920, *El Paso*, and the FPA.[71]

22. To the extent that WestConnect CTOs request that the Commission address in this order the appropriate geographic scope of the WestConnect transmission planning region or any other transmission planning region,[72] we decline to address such a request here because it is outside the scope of this proceeding.[73] We further note that the Commission responded to these concerns in the Remand Rehearing Order and continued to find that the WestConnect transmission planning region complies with Order No. 1000's

[71] *Id*. at 361-62; WestConnect Remand Order, 189 FERC ¶ 61,028 at PP 15-17.

[72] *See* WestConnect CTOs Rehearing Request at 9 n.17.

[73] The Commission has declined to evaluate the appropriate geographic scope of any particular transmission planning region in our transmission planning rules. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 160; Order No. 890, 118 FERC ¶ 61,119 at P 527. Instead, it is Commission practice to evaluate the proper scope of transmission planning regions in individual compliance or FPA section 205 proceedings. *See, e.g.*, *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,059, at P 31 (2013); *Louisville Gas & Elec. Co.*, 144 FERC ¶ 61,054, at PP 28, 30 (2013), *order on reh'g*, *Duke Energy Carolinas, LLC*, 147 FERC ¶ 61,241, at PP 46, 48 (2014); *Me. Pub. Serv. Co.*, 142 FERC ¶ 61,129, at P 21 (2013); *S. Co. Servs., Inc.*, 124 FERC ¶ 61,265, at P 71 (2008). *See also PacifiCorp*, 170 FERC ¶ 61,298, at P 29 (2020) (evaluating scope of transmission planning region proposed pursuant to FPA section 205).

requirement that the scope of a transmission planning region should be governed by the integrated nature of the regional power grid.[74]

## III. Regional Transmission Cost Allocation

### A. Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods

#### 1. Order Nos. 1920 and 1920-A

##### a. Inclusion in Transmission Providers' Compliance Filings of Relevant State Entities' Agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process

23. In Order No. 1920, the Commission: (1) required transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Method(s) for Long-Term Regional Transmission Facilities that are selected; and (2) permitted transmission providers to additionally revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process.[75]

24. The Commission also established in Order No. 1920 a six-month Engagement Period, during which transmission providers must, among other things, provide a forum for the negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities, and the Commission required transmission providers to explain on compliance

[74] *See* Remand Rehearing Order, 190 FERC ¶ 61,128 at PP 30-32.

[75] Order No. 1920, 187 FERC ¶ 61,068 at P 1291.

how they complied with the six-month Engagement Period requirements.[76] The Commission found that, if the Relevant State Entities participating in an Engagement Period agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and provide that Method(s) and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement,[77] the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. The Commission noted, however, that the ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.[78] The Commission did not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have

[76] *Id.* PP 1354, 1357.

[77] Order No. 1920 requires that transmission providers in each transmission planning region provide notice, such as on their OASIS or other public website, of the deadline for Relevant State Entities to communicate their agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, and this deadline must be no earlier than the end date of the Engagement Period. *Id.* P 1356.

[78] *Id.* PP 1359, 1363.

clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATT.[79]

25. In Order No. 1920-A, the Commission set aside Order No. 1920, in part, and required that, when Relevant State Entities notify transmission providers by the deadline for communicating agreement that they agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process resulting from the Engagement Period, the transmission providers must include that method or process in the transmittal or as an attachment to their compliance filing, even if the transmission providers propose a different Long-Term Regional Transmission Cost Allocation Method or do not propose to adopt a State Agreement Process.[80] The Commission further directed transmission providers to include in the transmittal or as an attachment to their compliance filings any information that Relevant State Entities provide to them regarding the state negotiations during the Engagement Period.[81] As part of this requirement, the

[79] *Id.* P 1429.

[80] Order No. 1920-A, 189 FERC ¶ 61,126 at P 651. The Commission clarified that, under this approach, the transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments, whether they decide to propose the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process or a different Long-Term Regional Transmission Cost Allocation Method. The requirement to include Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process as an addition to the compliance filing does not constitute a "proposal" from the transmission provider. *Id.* P 654 n.1651.

[81] *Id.* P 651.

Commission clarified that transmission providers must include any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing.[82]

26. The Commission found that the additional requirements adopted in Order No. 1920-A will allow the Commission to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period.[83] The Commission recognized that it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes.[84] The Commission found that Order No. 1920, as modified in Order No. 1920-A, strikes a reasonable balance between, on the one hand, recognizing the rights and responsibilities of the Commission and transmission providers over regional transmission planning and,

[82] *Id.* P 655. However, the Commission declined to require transmission providers to independently characterize this information. For example, the Commission did not require transmission providers to separately characterize Relevant State Entities' agreement or independently justify Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. *Id.*

[83] *Id.* P 657 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1357).

[84] *Id.* P 649 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1415).

on the other, the states' critical interests in the resulting Long-Term Regional Transmission Facilities and how the costs associated with those facilities will be allocated.[85]

27. Furthermore, noting that it was directing these facilitation and informational requirements on compliance pursuant to the Commission's authority under FPA section 206, the Commission found that these reforms do not implicate or infringe upon transmission providers' filing rights under FPA section 205.[86] The Commission reiterated its determination in Order No. 1920 that existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential under FPA section 206,[87] and that the Commission therefore has both the authority and responsibility to "determine the just and reasonable . . . practice . . . to be thereafter observed and in force," consistent with the Commission's findings in Order No. 1920.[88] The Commission explained that, pursuant to its authority under FPA section 206, the Commission required transmission providers to submit on compliance an *ex ante* cost allocation method. The Commission further explained that this compliance filing, submitted pursuant to FPA section 206, is not an

[85] *Id.* P 660.

[86] *Id.* P 657.

[87] *See id*. at P 652 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 113-114).

[88] *Id.* (quoting 16 U.S.C. 824e(a)).

FPA section 205 filing[89] and is thus distinct from any FPA section 205 filing that a transmission provider might file in the future following compliance to propose a change to its cost allocation method(s) for Long-Term Regional Transmission Facilities.[90]

### b. Commission Consideration of Relevant State Entities' Agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Processes

28. In Order No. 1920-A, the Commission noted that, when acting under FPA section 206, the Commission's statutory burden is to "establish *a* just and reasonable and not unduly discriminatory replacement rate that is supported by substantial evidence."[91] The Commission further noted that the statute does not necessarily require the Commission to adopt the transmission provider's proposal on compliance, even if that proposal complies with the final rule's requirements. Rather, the Commission need only select a replacement rate that complies with the final rule and that is adequately supported in the record, and then intelligibly explain the reasons for its choice.[92]

[89] *Id.* (citing *ISO New England Inc.*, 165 FERC ¶ 61,202 (2018), *order on reh'g*, 173 FERC ¶ 61,204, at P 8 (2020)).

[90] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1430).

[91] *Id.* P 658 (emphasis in original) (citing 16 U.S.C. 824e; 16 U.S.C. 825*l*(b)).

[92] *Id.* (citing *Entergy Ark., LLC v. FERC*, 40 F.4th 689, 701–02 (D.C. Cir. 2022) (*Entergy*) (noting that the Commission "is not required to choose the best solution, only a reasonable one" (first quoting *Petal Gas Storage, LLC v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); and then quoting *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 295 (2016) (*EPSA*)))).

29. The Commission recognized that, while it generally does not consider alternate compliance proposals other than those filed by the relevant public utility,[93] there are "good reasons" for considering such alternatives with respect to cost allocation under Order No. 1920.[94] The Commission explained that states play a unique role in Long-Term Regional Transmission Planning, as their laws, regulations, and policies drive the need for Long-Term Regional Transmission Facilities, and they typically will have responsibility to consider and approve the siting, permitting, and construction of Long-Term Regional Transmission Facilities selected in a regional transmission plan. As such, states affect whether Long-Term Regional Transmission Facilities are timely, efficiently, and cost-effectively developed such that customers actually receive the benefits associated with the selection of more efficient or cost-effective transmission solutions.[95] The Commission further found that given the inherent uncertainty involved in planning to meet Long-Term Transmission Needs, state-developed cost allocation methods and State Agreement Processes take on heightened importance.[96] The Commission explained that this means that it will consider the entire record—including

[93] *Id.* P 659 (citing *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134, at P 117 n.175 (2020); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 115 (2007); *ANR Pipeline Co.*, 110 FERC ¶ 61,069, at P 49 (2005)).

[94] *Id.* (quoting *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 515).

[95] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362-1364, 1404, 1407, 1410-1411, 1415, 1477, 1515).

[96] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 227).

the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate. Specifically, the Commission found that it is not required to accept a cost allocation proposal from a transmission provider on compliance simply because it may comply with Order No. 1920 but may adopt any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920.[97]

### 2. Challenges to Order No. 1920-A

#### a. Statutory Filing Rights Under the FPA

##### i. Rehearing Requests

30. Several of the rehearing requests argue that Order No. 1920-A unlawfully impinges on transmission providers' FPA section 205 filing rights by requiring transmission providers to include, in their transmittal or as an attachment to their compliance filings, Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.[98] Multiple

[97] *Id.*

[98] *See, e.g.*, SPP TOs Rehearing Request at 7, 12-15 (alternately describing Order No. 1920-A as requiring transmission providers to include Relevant State Entities' preferred Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings, or as granting "preferential filing privileges" to Relevant State Entities); Indicated PJM TOs Rehearing Request at 6 (describing Order No. 1920-A as "granting filing rights" to Relevant State Entities); MISO TOs Rehearing Request at 20 (describing Order No. 1920-A a "giv[ing] filing rights to Relevant State Entities").

rehearing petitioners assert that this requirement in Order No. 1920-A is inconsistent with the division of authority set forth in the FPA, which provides public utilities with unilateral and exclusive FPA section 205 filing rights to propose rates, terms, and conditions of service, and provides the Commission with the authority to modify existing rates under FPA section 206 after finding that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential.[99]

31. Rehearing petitioners contend that requiring transmission providers to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings unlawfully conditions or encumbers transmission providers' FPA section 205 filing rights. MISO TOs state that this requirement disrupts the balance set by FPA sections 205 and 206—allowing FPA section 206 to usurp FPA section 205—and encroaches on transmission providers' FPA section 205 filing rights.[100] MISO TOs and

[99] *See, e.g.*, MISO TOs Rehearing Request at 5-7 (arguing that Order No. 1920-A disrupts the balance between the filing rights afforded to public utilities under FPA section 205 versus those afforded to the Commission under FPA section 206); *id.* at 7-8; SPP TOs Rehearing Request at 3; *id.* at 4-5 ("The FPA's distinction between section 205 and 206 filing rights is well-established and binding on the Commission."); EEI Rehearing Request at 7-8; WIRES Rehearing Request at 7-8, 10-11; Indicated PJM TOs Rehearing Request at 3-4.

[100] *See, e.g.,* MISO TOs Rehearing Request at 6-7; *id.* at 10-11; ("[T]he Commission uses its FPA section 206 authority to mandate a broad encroachment on transmission providers' FPA section 205 filing rights. Given this encumbrance, transmission providers will be unable to exercise the full breadth of their FPA section 205 rights."); *id.* at 24-27 (arguing also that even if FPA sections 205 and 206 are ambiguous as to whether the Commission has this authority, a reviewing court will no longer afford the Commission's interpretation deference).

SPP TOs argue that states may not force public utilities to make FPA section 205 filings or require them to relinquish their filing rights to other entities.[101] Indicated PJM TOs assert that this requirement "effectively forces utilities to cede their filing rights to others, contravening the statutory directive by Congress in [FPA] section 205 that grants utilities the exclusive right to propose their rates and terms of service."[102]

32. Some rehearing petitioners assert that the Commission misconstrues the structure of FPA sections 205 and 206, and particularly the rights afforded to public utilities under FPA section 205. For instance, they argue that FPA section 205 is intended for the benefit of the public utility, granting it the proactive right to initiate rate changes, in contrast to the passive role played by the Commission under that provision.[103] Rehearing petitioners also assert that the FPA section 205 rights of public utilities to initiate rate

[101] *Id.* at 18 (citing *Mass. Dep't of Pub. Utils v. FERC*, 729 F.2d 886, 886-87 (1st Cir. 1984) (*Massachusetts Department of Public Utilities*)); SPP TOs Rehearing Request at 4-5 (asserting that "states may not force public utilities to make section 205 filings"); *see also id.* at 5-6 (arguing that circumstances in which public utilities voluntarily cede statutory filing rights to others are distinct from those in which the Commission attempts to encroach on those rights).

[102] Indicated PJM TOs Rehearing Request at 2; *id.* at 10-11. *See also* EEI Rehearing Request at 6-8 (arguing that this requires utilities to file cost allocation methods they are opposed to and that the Commission did not identify text in the FPA authorizing this approach); WIRES Rehearing Request at 2, 15 (same).

[103] *See, e.g.*, MISO TOs Rehearing Request at 5-6 (citing *Emera Me. v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017) (*Emera Maine*)); *id.* at 8-9, 11, 20, 25; Indicated PJM TOs Rehearing Request at 3-4, 19 n.69; *see also* SPP TOs Rehearing Request at 3.

changes are exclusive and unilateral.[104] Rehearing petitioners further contend that public utilities are the entities entitled to submit filings under FPA section 205 to set their rates and initiate rate changes.[105]

33. In addition, petitioners cite precedent that, they contend, reflects the fact that the Commission cannot diminish public utilities' FPA section 205 filing rights and, therefore, Order No. 1920-A's requirement for transmission providers to submit Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process with their compliance filings is unlawful. Many of the rehearing requests argue that the requirement to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings is contrary to *Atlantic City Electric. Co. v. FERC*.[106] They assert that *Atlantic City I* holds that public utilities—and only public utilities—have FPA section 205 filing rights to propose rate changes and that public utilities cannot be involuntarily divested of those rights as a result

[104] *See, e.g.*, Indicated PJM TOs Rehearing Request at 2-3, 10, 16; MISO TOs Rehearing Request at 5, 8, 12-15; SPP TOs Rehearing Request at 5; EEI Rehearing Request at 6-8, 12-13; WIRES Rehearing Request at 6.

[105] *See, e.g.*, WIRES Rehearing Request at 6, 8; EEI Rehearing Request at 10-11, 11 n.34; SPP TOs Rehearing Request at 9, 16 n.43, 19, 21; Indicated PJM TOs Rehearing Request at 7.

[106] 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City I*); *see also Atl. City Elec. Co. v. FERC*, 329 F.3d 856 (D.C. Cir. 2003) (*Atlantic City II*) (granting a petition for review seeking to enforce the mandate of *Atlantic City I* in response to the Commission's order on remand after *Atlantic City I*).

of an FPA section 206 compliance directive.[107] Several rehearing petitioners point to other decisions that, they contend, rejected attempts by the Commission to limit or compromise public utilities' (or, in the parallel context of the Natural Gas Act (NGA),[108] natural-gas companies') statutory authority to file rates.[109] A number of the rehearing requests also rely on *Massachusetts Department of Public Utilities*,[110] asserting that

[107] *See* MISO TOs Rehearing Request at 11-15 (discussing *Atlantic City I* and *Atlantic City II*, and asserting that these cases "stand as foundational determinations about the lawful statutory framework created by Congress vesting certain rights in public utilities under FPA section 205 and other rights in the Commission under section 206, and denying the Commission authority to overextend its authority under FPA section 206 when directing public utilities on compliance"); Indicated PJM TOs Rehearing Request at 2, 6, 11-12 (arguing that the requirement to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in the transmittal or as an attachment to transmission providers' compliance filing forces transmission providers to cede their exclusive rights to Relevant State Entities and grants Relevant State Entities rights not provided by the FPA); SPP TOs Rehearing Request at 4-5, 9, 11-16; EEI Rehearing Request at 8-9 ("The precedent in *Atlantic City II*, is clear—the Commission cannot condition or encumber a utility's right under FPA section 205 to initiate rate changes, even as a result of an FPA section 206 compliance directive."); WIRES Rehearing Request at 5-6, 8, 10.

[108] 15 U.S.C. 717, *et seq.*

[109] *See, e.g.*, SPP TOs Rehearing Request at 5 (citing *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017) (*NRG Power Mktg.*); *Pub. Serv. Comm'n of N.Y. v. FERC*, 866 F.2d 487, 488-89 (D.C. Cir. 1989) (*NYPSC*); *W. Res., Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993) (*Western Resources*); *Consumers Energy Co. v. FERC*, 226 F.3d 777, 780 (6th Cir. 2000); *Louisiana v. FPC*, 503 F.2d 844, 861 (5th Cir. 1974)); MISO TOs Rehearing Request at 9, 16 (citing *NRG Power Mktg.*, 862 F.3d 108; *Emera Maine*, 854 F.3d 9; *PJM Power Providers Grp. v. FERC*, 88 F.4th 250, 270 n.122 (3d Cir. 2023)).

[110] 729 F.2d at 888.

"states may not force public utilities to make section 205 filings" or require utilities to submit "'regulator-compelled' utility-proposed changes."[111]

34. MISO TOs assert that Order No. 1920-A contravenes restrictions on the Commission's FPA section 206 authority because, by requiring attachment of Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to transmission providers' compliance filings, it requires transmission providers to relinquish their right to file rate changes under FPA section 205 to Relevant State Entities.[112] MISO TOs argue that the Commission in Order No. 1920 acknowledged that it could not encumber these filing rights by initially allowing transmission providers to determine which Long-Term Regional Transmission Cost Allocation Method(s) to file as part of their compliance filings.[113] Indicated PJM TOs assert that FPA section 206 "does not authorize the Commission to provide [Relevant State Entities] with the statutory authority reserved solely to public utilities,

[111] SPP TOs Rehearing Request at 4-5; EEI Rehearing Request at 8 n.27; Indicated PJM TOs Rehearing Request at 6, 10; *see also* MISO TOs Rehearing Request at 9, 18, 25.

[112] MISO TOs Rehearing Request at 16-19 (arguing that this effectively forces transmission providers to make FPA section 205 filings that are not their own; also characterizing this as involuntarily transferring to Relevant State Entities the right to make FPA section 205 filings to make rate changes (citing *Atlantic City I*, 295 F.3d at 9-11; *Atlantic City II*, 329 F.3d at 858-59; *NRG Power Mktg.*, 862 F.3d at 114; *PJM Power Providers Grp.*, 88 F.4th at 270 n.122; *Emera Maine*, 854 F.3d at 24)).

[113] *See id.* at 16-17 (noting that, under Order No. 1920, filing a Relevant State Entity's proposed Long-Term Regional Transmission Cost Allocation Method was voluntary).

nor does it authorize the Commission to require public utilities to cede those rights to [Relevant State Entities] by forcing them to submit proposals and materials prepared by those [Relevant State Entities] that the public utilities do not support."[114] EEI argues that, "[b]y requiring the public utilities to file the Relevant State Entities' proposals, the Commission is requiring those public utilities to cede their statutory rights to make filings under the FPA to the Relevant State Entities and to provide those entities with statutory rights that Congress did not intend them to have."[115] SPP TOs argue that Order No. 1920-A gives "preferential filing privileges to states that the FPA does not authorize the Commission to grant," and thereby diminishes the FPA section 205 filing rights of public utilities.[116] WIRES states that the Commission does not have statutory authority to require a public utility to file another entity's rate proposal, and that Order No. 1920-A

[114] Indicated PJM TOs Rehearing Request at 11-12 (citing 16 U.S.C. 824d; *Atlantic City I*, 295 F.2d at 9-11; *Massachusetts Department of Public Utilities*, 729 F.2d at 888).

[115] EEI Rehearing Request at 8 (citing *Atlantic City II*, 329 F.3d at 858-59) (arguing that the Commission "acknowledges this when it concedes that it generally does not consider alternate compliance proposals other than those filed by the relevant public utility" (quotation marks omitted)); *see id.* at 9-12 (arguing that under the FPA the Commission may not, in setting a replacement rate, divest public utilities of their filing rights and give them to Relevant State Entities).

[116] SPP TOs Rehearing Request at 13; *see id.* at 14 ("The FPA does not contemplate any party, including states, being allowed to make compliance filings on a regulated public utility's behalf. Nor does it authorize third parties to somehow join or commandeer a public utility's compliance filing."); *id.* at 17 ("The fact that states are unable to file cost allocation methods themselves and must instead either comment on transmission providers' proposals or file section 206 complaints is exactly what the FPA requires." (quotation marks omitted)).

does not reflect a "mere change in the filing process" but rather a substantive change that the Commission is not authorized to make.[117] WIRES further argues that Order No. 1920-A effectively elevates states to the equivalent of public utilities in requiring that their proposals be included in the compliance filing, which will be assessed under the same just and reasonable standard articulated in FPA section 205.[118]

35. Many rehearing petitioners also contest the Commission's explanation for why this compliance filing requirement was statutorily permissible. MISO TOs assert that the Commission's explanation that a Relevant State Entity's proposed method or process does not constitute a "proposal" is an "empty formalism with no grounding in the statutory text" that does not change the impact of the requirement on transmission

[117] WIRES Rehearing Request at 11-12; *id.* at 13 ("[B]y requiring a transmission provider to include in its compliance filing a state-agreed upon method or process, the transmission provider is forced to share its statutory filing rights with another entity under a just and reasonable standard.").

[118] *See id.* at 13-14 (arguing that the Commission has not previously taken the approach set forth in Order No. 1920-A and that, as the Commission recognizes, transmission planning is the tariff obligation of transmission providers); *see also id.* at 10-11 ("Procedurally, the public utility's obligation under compliance is the same as that under FPA section 205, *i.e.*, the public utility must submit a just and reasonable rate."); *id.* at 15-16 ("Whether a filing is submitted under FPA section 205 or 206, the public utility's filing is equally subject to a just and reasonable standard, as both statutory provisions ultimately rely on the same standard."); *cf.* SPP TOs Rehearing Request at 30 (claiming that "[t]he Commission failed to acknowledge that it was changing policy when it decided to afford public utility and state proposals equal status when the Commission's previous approach was to favor compliance proposals by the regulated entities that were the actual subject of compliance mandates").

providers' FPA section 205 filing rights.[119] WIRES similarly argues that, despite this clarification and the fact that transmission providers are not required to characterize or justify the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process,[120] the compliance requirement remains unlawful because neither states nor Relevant State Entities are public utilities entitled to make FPA section 205 filings.[121]

36. MISO TOs argue that the Commission's distinction between FPA section 205 filings and compliance filings under FPA section 206 is a "hollow explanation" that does not allow the Commission to give filing rights to Relevant State Entities in violation of the FPA or require public utilities to cede their filing rights under FPA section 205.[122] SPP TOs acknowledge that Commission precedent distinguishes between FPA section 205 filings and compliance filings under FPA section 206,[123] but still contend that Order No. 1920-A's mandates are unlawful because they are forced encroachments on

[119] MISO TOs Rehearing Request at 19 (quoting Order No. 1920-A, 189 FERC ¶ 61,126 at P 654 n.1651).

[120] WIRES Rehearing Request at 13 (quoting Order No. 1920-A, 189 FERC ¶ 61,126 at PP 654 n.1651, 655).

[121] *See id.*

[122] MISO TOs Rehearing Request at 19-20.

[123] SPP TOs Rehearing Request at 3-4 (citing *N.Y. Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,242, at P 32 (2010); *PJM Interconnection, L.L.C.*, 85 FERC ¶ 61,111, at 61,413 (1998); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 5-7, 21 (2013)).

public utility filing rights under the FPA, which may only be relinquished voluntarily.[124] EEI also recognizes that a compliance filing under FPA section 206 is not a change initiated by a public utility but rather one directed by the Commission,[125] but asserts that, even if the Commission were to act pursuant to FPA section 206 or via rulemaking, whatever rate or regulation the Commission establishes may not usurp the rights of public utilities to file proposed rates.[126]

37. SPP TOs argue that the Commission has rejected attempts to use compliance filings to bypass the FPA's filing requirements and circumvent FPA notice requirements, and that the Commission has recognized that it could not circumvent these requirements even by invoking FPA section 309.[127] They contend that the Commission's approach could lead it to improperly "bypass" FPA sections 205 and 206 in future cases, e.g., in complaint proceedings, by authorizing "favored parties to include their preferred alternative remedies in other parties' compliance filings without first having to make the first step showings under FPA section 206 that are normally required of complainants or

[124] *See id.* at 4-5 ("Courts have firmly rebuffed various attempts to alter the FPA framework, especially when the purpose was to weaken public utilities' ability to independently exercise their statutory filing rights."); *id* at 6.

[125] EEI Rehearing Request at 8-9 (citing *S. Co. Servs, Inc.*, 61 FERC ¶ 61,339, at 62,328-29 (1992), *order on reh'g*, 63 FERC ¶ 61,217 (1993)).

[126] *Id*. at 9 (citing *Atlantic City I*, 295 F.3d at 10-11).

[127] SPP TOs Rehearing Request at 15 (citing 16 U.S.C. 825h; *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,083, at P 29 (2022)).

protestors."[128] SPP TOs claim that Order No. 1920-A's attempt to weaken FPA sections 205 and 206's statutory constraints wrongly attempts to resolve a "major question" under the statute in ways that Congress did not authorize and could not have foreseen.[129]

38. Indicated PJM TOs argue that Order No. 1920-A's requirement to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings intrudes into the decision making processes of public utilities as to whether to submit a filing under FPA section 205.[130] Indicated PJM TOs state that these are "internal decisions by the public utility determined by its governing authority" that are beyond the Commission's authority to regulate and contrary to the "passive role" assigned to the Commission under FPA section 205.[131] They assert that this requirement is a "direct intervention into a public utility's decision regarding what to file even before the filing is

[128] *Id*. at 15 & n.39 ("The states or third parties would not have to show that the existing rates were unjust and unreasonable as they would under section 206.").

[129] SPP TOs Rehearing Request at 17-18 (citing *Biden v. Neb.*, 143 S. Ct. 2355, 2374 (2023); *W. Va. v. EPA*, 597 U.S. 697, 724 (2022)).

[130] Indicated PJM TOs Rehearing Request at 2-3, 6-7, 12-15.

[131] *Id.* at 12-15 (also arguing that under *EPSA*, 577 U.S. 260 and *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 403 (D.C. Cir. 2004) (*CAISO*), the Commission's authority is limited to regulating practices directly affecting jurisdictional rates and does not extend to regulating how a public utility makes decisions).

made" and not a "practice affecting a rate" subject to Commission regulation.[132] Indicated PJM TOs further assert that Commission precedent addressing RTO/ISO governance is not relevant, as the two cases addressing participation in the bodies that vote on rate proposals were decided prior to the Supreme Court's decision in *Loper Bright Enterprises v. Raimondo*, did not "advance[ ] to judicial review," and did not "address[ ] the D.C. Circuit's decision in *CAISO*."[133]

39. EEI, SPP TOs, and WIRES assert that there are other avenues for parties to be heard with respect to cost allocation, such that infringing on transmission providers' FPA section 205 rights is not necessary or justified. EEI argues that parties may file protests to a transmission provider's compliance filing if they wish to advocate for an alternative approach.[134] SPP TOs argue that, because states are not authorized to file cost allocation proposals, they are limited to commenting on or protesting transmission providers' proposals or filing FPA section 206 complaints.[135] WIRES argues that there are ways of evaluating whether transmission providers have provided state regulators with a formal

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[132] *Id.* at 14 (citing *Atlantic City I*, 295 F.3d at 10).

[133] *Id.* at 15 (citing *PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,147, *order on reh'g,* 157 FERC ¶ 61,229 (2016); *New England Power Pool Participants Comm.*, 166 FERC ¶ 61,062 (2019)).

[134] EEI Rehearing Request at 9-10 (arguing that "[t]he Commission fails to explain what procedural infirmity would be created by requiring Relevant State Entities and other stakeholders to provide comments and feedback on these filings throughout the traditional regulatory process" and that the approach adopted in Order No. 1920-A could lead to confusion as to which proposal to provide feedback on); *see also id.* at 12.

[135] SPP TOs Rehearing Request at 17-18; *see also id.* at 15-16, 18-19.

opportunity to develop a Long-Term Regional Transmission Cost Allocation Method other than compelling transmission providers to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filing, but that Order No. 1920-A adopts an adversarial approach of dueling compliance proposals.[136]

40. MISO TOs assert that, under Order No. 1920-A, the Commission is particularly likely to accept Relevant State Entities' Long-Term Regional Transmission Cost Allocation Methods rather than transmission providers proposals because they assert that Order No. 1920-A provides that Relevant State Entities' proposals "will be afforded heightened preference over transmission providers' own proposals."[137] MISO TOs argue that accepting Relevant State Entities' cost allocation method over the transmission provider's proposed cost allocation method would "subvert[ ] future FPA section 205 filings related to that rate scheme in a manner that disfavors the transmission provider's FPA section 205 proposals."[138]

41. Indicated PJM TOs and SPP TOs argue that, in claiming that the Commission need not accept a transmission provider's proposal on compliance even if the proposal complies with the final rule's requirements, the Commission's reliance on

[136] WIRES Rehearing Request at 14.

[137] MISO TOs Rehearing Request at 7; *see id.* at 24-25 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 659); *id.* at 9, 33-37.

[138] *Id.* at 24-25.

*Entergy Arkansas, LLC v. FERC* is misplaced.[139] They contend that *Entergy* is inapposite because the Commission there rejected MISO's compliance filing before selecting a different replacement rate.[140] SPP TOs argue that the Commission can accept a proposed replacement rate from a third party (including Relevant State Entities) only after finding that the transmission provider's compliance filing does not comport with the Commission's directives.[141]

42. Indicated PJM TOs assert that the preference the Commission has articulated in its precedent for accepting public utilities' compliant, just and reasonable proposals rather than competing proposals[142] is, in fact, mandated by the FPA.[143] Indicated PJM TOs state that FPA sections 205 and 206 are part of a single statutory structure under which rates

[139] Indicated PJM TOs Rehearing Request at 22-23 (citing *Entergy*, 40 F.4th at 701-02); SPP TOs Rehearing Request at 18-19 n.49 (same); *see* Order No. 1920-A, 189 FERC ¶ 61,126 at P 658 & n.1656.

[140] Indicated PJM TOs Rehearing Request at 22-23; SPP TOs Rehearing Request at 18-19 & n.49 ("[S]tates, like every other third party, should have to show that a public utility's proposed replacement rate does not satisfy compliance directives before their preferred alternatives are considered.").

[141] SPP TOs Rehearing Request at 14-15.

[142] *See infra* P 74 (summarizing arguments that the Commission departed from this precedent without adequate explanation).

[143] Indicated PJM TOs Rehearing Request at 17-18 (arguing that "[t]he statutory structure of the FPA requires the Commission give preference to the proposal submitted on compliance by public utilities" and the Commission "cannot simply choose the one it likes best" (citing *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 340-41 (1956))); *see id.* at 20 ("This preference for the public utility's proposal is the only interpretation that conforms with the statutory text of the FPA.").

are initially established by the utility, such that the Commission must give preference to compliance proposals by public utilities over those by other entities.[144]

43. Indicated PJM TOs also assert that Order No. 1920-A "did not prescribe a specific replacement rate," instead maintaining a "light touch" and providing flexibility to transmission providers as to their compliance filings on cost allocation, and therefore "forwent its opportunity to establish a specific replacement rate pursuant to section 206."[145] Indicated PJM TOs further maintain that the Commission's approach in Order Nos. 1920 and 1920-A is inconsistent with FPA section 206, which Indicated PJM TOs state requires that the replacement be "fixed by rule or by a later order on compliance, but not by both."[146] As a result, Indicated PJM TOs claim that "any later filing made by the public utility to ensure that the public utility is compliant with the Commission's rules is made pursuant to section 205"[147] such that the Commission's "only recourse is to consider whether the rate submitted by the public utility on compliance is just and reasonable."[148] WIRES similarly argues that the Commission did

[144] *See id.* at 17.

[145] *Id.* at 27-28.

[146] *Id.* at 27 n.102 (citing 16 U.S.C. 824e(a); *Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,165, at PP 21-26 (2009)).

[147] *Id.* at 27-28 n.102.

[148] *Id.* at 28; *see also, e.g.*, *id.* at 3-4 ("Unless the Commission prescribes the specific replacement rate, the Commission must accept the utility's filing if it is just and reasonable, even if the Commission prefers a different rate."); *id.* at 5, 7-8.

not "take the initiative in setting the replacement rates" but instead directed transmission providers on compliance to submit just and reasonable cost allocation methods consistent with the requirements of Order No. 1920, such that "the public utility need only propose a just and reasonable replacement rate in compliance with the Commission order."[149]

44. SPP TOs argue that certain Commission precedent cited in Order No. 1920-A[150] does not support—and, in fact, undermines—the requirement that transmission providers submit Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process with transmission providers' compliance filings.[151]

### ii. Commission Determination

45. For the reasons below and those stated in Order No. 1920-A, we sustain the Commission's determination in Order No. 1920-A requiring transmission providers to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process resulting from the Engagement Period, and associated information provided to transmission providers regarding the state

[149] WIRES Rehearing Request at 10-11.

[150] Order No. 1920-A, 189 FERC ¶ 61,126 at P 658 & n.1657 (citing *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 at P 117 n.175; *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 115; *ANR Pipeline Co.*, 110 FERC ¶ 61,069 at P 49) (reflecting that the Commission typically does not consider alternative proposals on compliance).

[151] *See* SPP TOs Rehearing Request at 16-17 & n.43 (arguing that these cases involved acceptance of and/or giving greater weight to transmission providers' compliance filings or settlement proposals).

negotiations during the Engagement Period, in transmission providers' transmittal or as an attachment to their Order No. 1920 regional transmission planning and cost allocation compliance filings.[152] We further sustain the Commission's determination that, pursuant to its FPA section 206 authority, it will consider the entire record—including any agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and the transmission providers' proposal—when setting the replacement rate.[153]

### (a) The Statutory Text and Structure, and Applicable Precedent, Support the Commission's Order No. 1920-A Approach

46. Order No. 1920-A requires that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated information in the transmittal or as an attachment to their Order No. 1920 compliance filings and provides for the Commission's consideration of the entire record, which includes proposals from transmission providers and attachments to transmission providers' filings, when finalizing the replacement rate. The challenges raised on rehearing to both of these aspects of Order No. 1920-A incorrectly treat filings to comply with Order Nos. 1920 and

[152] Order No. 1920-A, 189 FERC ¶ 61,126 at PP 651, 654-655.

[153] *Id.* P 659. As discussed further below, pursuant to FPA section 205, transmission providers retain their discretion over whether to make and the contents of any future FPA section 205 filings, and Order No. 1920-A's requirements do not affect that discretion. *See infra* PP 69, 118.

1920-A as arising under or implicating FPA section 205, which sets forth public utilities' filing rights and obligations. Rather, these aspects of Order No. 1920-A arise from FPA section 206, which sets forth the Commission's authority to determine and fix by order a replacement rate after appropriate findings.[154] The compliance filings required by Order Nos. 1920 and 1920-A are a tool to implement the Commission's authority under FPA section 206, and do not implicate public utilities' rights and obligations under FPA section 205. Thus, we address at the outset the statutory text and structure of the FPA, as well as relevant Commission and judicial decisions, in addressing these arguments.

47. Order Nos. 1920 and 1920-A were issued pursuant to Commission-initiated proceedings under FPA section 206.[155] As the Commission stated in Order No. 1920-A, having determined that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential under FPA section 206, "[t]he Commission thus had both the authority and responsibility to 'determine the just and reasonable . . . practice . . . to be thereafter observed and in force.'"[156] The Commission required the submission of compliance filings to assist in effectuating the Commission's authority under FPA section 206,

[154] 16 U.S.C. 824d (setting forth public utility filing rights and obligations); 16 U.S.C. 824e (setting forth power of Commission to fix rates and charges).

[155] *See Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 179 FERC ¶ 61,028, at P 1 (2022) (NOPR); Order No. 1920, 187 FERC ¶ 61,068 at P 1; Order No. 1920-A, 189 FERC ¶ 61,126 at PP 1, 652.

[156] Order No. 1920-A, 189 FERC ¶ 61,126 at P 652 (quoting 16 U.S.C. 824e(a)).

explaining in Order No. 1920-A that "[t]his compliance filing submitted pursuant to FPA section 206 is not an FPA section 205 filing."[157]

48. While FPA sections 205 and 206 embody a complementary structure for regulating the rates and practices of public utilities, they are distinct provisions which assign rights and responsibilities to different entities under different circumstances. FPA section 205 requires that the public utility, subject to Commission oversight, "file with the Commission . . . schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges."[158] FPA section 206(a), by contrast, delineates the authority of the Commission—the subject of the provision—to modify public utilities' existing rates on appropriate findings and, itself, determine and fix by order the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be observed and in force.[159]

49. The express text of FPA section 206 does not provide public utilities with statutory filing rights with respect to the just and reasonable replacement rate following a

[157] *Id.* (citing *ISO New England Inc.*, 173 FERC ¶ 61,204 at P 8).

[158] 16 U.S.C. 824d(c); *cf. id.* 824d(a) (requiring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful").

[159] 16 U.S.C. 824e(a) (providing that "the Commission shall determine" the replacement rate and "shall fix the same by order").

finding that existing rates are unjust, unreasonable, or unduly discriminatory or preferential. Rather, the authority to "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force" is vested in the Commission, and—in Commission-initiated proceedings under FPA section 206—the Commission must find that the replacement rate it determines and fixes meets the statutory criteria.[160] To implement this authority the Commission frequently requires public utilities to submit compliance filings, as it did in Order Nos. 1920 and 1920-A, which the Commission will review and address in further orders.[161]

50. As the D.C. Circuit held in discussing what it means to "'fix' a rate within the meaning of [FPA section 206]," when the Commission determines that an existing rate is

[160] *Id.*; *see E. Tenn. Nat. Gas Co. v. FERC*, 863 F.2d 932, 937 (D.C. Cir. 1988) (explaining that, under the parallel provisions of the NGA, "[w]hen review of existing rates is initiated by the Commission, . . . the burden of proving that the existing rates are unjust or unreasonable, and that those it orders in replacement are just and reasonable, rests with [the Commission]"); *ISO New England Inc.*, 153 FERC ¶ 61,224, at P 24 (2015) ("The Commission did not place the burden on Connecticut and Rhode Island to prove that the dynamic de-list bid threshold [proposed in a compliance filing] was unreasonable. Rather, the Commission affirmatively found the dynamic de-list bid threshold to be just and reasonable.").

[161] *See, e.g.*, *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, at P 1762, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024); *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 360 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021). This particular compliance process, however, is not prescribed by the statute and by no means required. *See Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 494 (D.C. Cir. 1985) (*Electrical District*) (explaining that the Commission may instead "complete the process itself and fix the rates in its initial order").

unjust and unreasonable, it is not "inevitable that the Commission has the obligation to end an unlawful rate from the moment it finds unlawfulness."[162] The court therefore rejected the Commission's argument that a replacement rate necessarily must go into effect as of the date the Commission finds that an existing rate is not lawful under the FPA, rather than the effective date provided when the Commission determines and fixes the replacement rate on compliance.[163] This decision underscores that the Commission's authority and responsibility under FPA section 206 to fix the replacement rate continued, in the Order Nos. 1920 and 1920-A context, from the point at which the Commission determines that existing rates are unlawful and requires compliance filings until the Commission fixes the replacement rate by order.[164] The submission and Commission

[162] *Electrical District*, 774 F.2d at 492. The D.C. Circuit later explained how this decision could be reconciled with *Pub. Serv. Co. of New Hampshire v. FERC*, 600 F.2d 944 (D.C. Cir. 1979), which applied a seemingly lower standard with respect to the necessary notice required under the FPA as to certain types of rates. *See Transwestern Pipeline Co. v. FERC*, 897 F.2d 570, 577-78 (D.C. Cir. 1990). The reconciliation of these cases does not affect the relevance of the analysis from the D.C. Circuit discussed herein regarding the Commission's ongoing FPA section 206 authority.

[163] *See Electrical District*, 774 F.2d at 492 ("Or to use a more remote analogy, it is not the case that once a court has concluded that a particular action challenged before it is unlawful it must immediately issue an injunction, instead of taking time for further deliberations necessary to determine what the precise terms of that injunction should be."); *see also Kern River Gas Transmission Co.*, 133 FERC ¶ 61,162, at P 22 (2010) (*Kern River*) ("Since *Electrical District*, the Commission's general practice in determining the effective date of rate changes ordered pursuant to NGA section 5 has been to follow the approach suggested by the court in that case.").

[164] *See Electrical District*, 774 F.2d at 492 (citing FPA section 206(a), 16 U.S.C. 824e(a), as establishing "the procedures that the statute establishes for adjusting unlawful rates" and finding that these procedures for the Commission to follow in fixing the replacement rate by order, pursuant to the statutory text are "not at all ambiguous").

consideration of compliance filings pursuant to those orders, and the Commission's subsequent determination of the replacement rate, are thus later stages occurring as part of a continuing process under FPA section 206, not under FPA section 205.[165] Accordingly, the Commission has distinguished compliance filings that assist the Commission's exercise of its authority under FPA section 206 from other filings made by public utilities under the distinct rights afforded to them under FPA section 205.[166]

51. FPA section 206 does not prevent the Commission, after having found an existing rate unjust and unreasonable, from choosing in a specific rulemaking proceeding to

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[165] *See id.* Similarly, *Entergy* recognizes that the Commission may select the just and reasonable rate in an FPA section 206 proceeding and that its authority to do so remains intact throughout the compliance process. 40 F.4th at 701-02. This stands in contrast to FPA section 205 proposals where the Commission's role is passive and reactive. *See City of Winnfield, La. v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984) (*City of Winnfield*); *NRG Power Mktg.*, 862 F.3d at 114.

[166] *See, e.g.*, *ISO New England Inc.*, 173 FERC ¶ 61,204 at P 8 (explaining that a filing from ISO-NE would be considered as a new FPA section 205 filing, rather than a compliance filing related to an FPA section 206 investigation, because the Commission "did not make a finding that ISO-NE's tariff was unjust and unreasonable without such revisions, a necessary precursor to the Commission considering ISO-NE's tariff revisions as a compliance filing setting forth a proposed replacement rate"); *N.Y. Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,242 at P 32 (stating that "the Commission has always treated compliance filings differently than a company-initiated rate change application filed pursuant to section 205 of the FPA," including that they are not subject to the 60-day prior notice requirement under section 205(d) of the FPA); *Ameren Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,186, at P 28 (2010) (finding that aspects of a filing exceeded the scope of compliance and should, instead, have been submitted under FPA section 205); *PJM Interconnection, L.L.C.*, 85 FERC ¶ 61,111 at 61,413 ("Although PJM purported to file its market monitoring plan in part pursuant to Section 205 of the FPA, it was in fact a filing in compliance with Ordering Paragraph V of the November 25 Order. Such compliance filings are pursuant to a Commission directive and are not subject to the procedures of Section 205(d).") (cleaned up).

consider the approaches of entities other than the public utility to inform the Commission's determination of the replacement rate;[167] rather, it states that "the Commission shall determine the just and reasonable rate" to be thereafter observed and in force.[168] It also does not preclude the Commission from requiring that transmission providers submit Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process with transmission providers' compliance filings.[169] Neither does FPA section 205, which governs the distinct process of a public utility filing its own rates in the first instance, subject to Commission oversight,[170] rather than the determination of a replacement rate by the Commission after appropriate findings under FPA section 206. Moreover, that a public utility is the entity that submits a compliance filing does not transform that

[167] As discussed below, Order No. 1920-A's approach to considering compliance filings on cost allocation represents a limited departure, in these particular circumstances, from the Commission's typical approach of adopting public utilities' proposals in compliance filings if they are compliant with the requirements of the final rule. *See infra* PP 86-87.

[168] 16 U.S.C. 824e(a).

[169] *See* 16 U.S.C. 824e(a), (b) (setting forth certain procedural requirements relating to proceedings under FPA section 206, which do not include such restrictions); *see also Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 38–39 (D.C. Cir. 2002) (*INGAA*) (holding under parallel provisions of the NGA that "the Commission has authority under [NGA section] 5 to order hearings to determine whether a given pipeline is in compliance with FERC's rules . . . and under [NGA sections] 10 and 14 to require pipelines to submit needed information for making its [NGA section] 5 decisions"); 16 U.S.C. 825c(a), 825f(a), 825h.

[170] *See* 16 U.S.C. 824d.

submission into an FPA section 205 filing, subject to the requirements of that provision.[171] A contrary conclusion would fail to recognize and give effect to the distinct and express statutory authority afforded to the Commission in FPA section 206, which arises pursuant to specific statutory findings and which, once triggered, is subject to different requirements than FPA section 205 filings.

52. We agree with rehearing petitioners that FPA section 205 expressly provides public utilities with statutory filing rights. But when considered in the correct statutory context, the arguments on rehearing that the Commission has intruded on those public utilities' FPA section 205 filing rights by: (1) requiring that public utilities attach to their compliance filings Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated information; or (2) considering, and potentially adopting, Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in determining the replacement rate, are not persuasive.[172] These aspects of Order No. 1920-A were adopted pursuant to FPA section 206, to assist in building the record for the Commission's exercise of its own authority to determine and fix the just and reasonable rate, as well as in monitoring compliance with the requirements related to the Engagement Period and efficiently considering the views of

[171] *See supra* P 50 & note 166 (discussing cases distinguishing compliance filings made by public utilities, which the Commission and courts consistently and correctly treated as made under FPA section 206, from FPA section 205 filings).

[172] *See supra* PP 30-31.

both Relevant State Entities and transmission providers. FPA section 205 is not implicated by these aspects of Order No. 1920-A and arguments to the contrary conflate compliance filings to assist the Commission in implementing its authority under FPA section 206 with public utilities' rate filings under FPA section 205.

53. Efforts to connect public utilities' FPA section 205 rights to this distinct FPA section 206 process by appealing to the structure of FPA sections 205 and 206[173] are misplaced for similar reasons; these arguments incorrectly blur the line between the separate authorities assigned in FPA sections 205 and 206. As the petitioners seeking rehearing observe, public utilities have the statutory right under FPA section 205 to file proposals to set and revise their rates of their own initiative in the first instance, and under that section, the Commission plays an essentially passive role in reviewing—and then accepting or rejecting—those proposals based on their consistency with the statutory requirements.[174] And as discussed below, public utilities retain their discretion as to whether to file—or not file—those proposals using this FPA section 205 authority.[175] But as to existing, Commission-approved rates, the FPA separately assigns to the Commission under FPA section 206 the authority to review those rates of its own

[173] *See supra* P 32.

[174] *See, e.g.*, EEI Rehearing Request at 13; Indicated PJM TOs Rehearing Request at 2-4; MISO TOs Rehearing Request at 5-6; SPP TOs Rehearing Request at 3, 5-6; WIRES Rehearing Request at 8.

[175] *See infra* P 118.

initiative or in response to a complaint.[176] Upon appropriate findings, the Commission—not the public utility—has the authority itself to determine and fix the replacement rate,[177] including determining such rate through the use of compliance filings.[178] Subsequently, public utilities may seek to revise that Commission-determined replacement rate through the exercise of their FPA section 205 rights.[179] FPA sections 205 and 206 are thus complementary provisions under a coherent statutory structure, but they embody a statutorily-imposed division of rights and responsibilities between public utilities under FPA section 205 and the Commission under FPA section 206.[180]

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[176] 16 U.S.C. 824e(a).

[177] *Id.*; *see also FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) (stating that, under FPA section 206, "[i]t is the Commission's job—not the petitioner's—to find a just and reasonable rate." (internal quotations omitted)).

[178] Arguments on rehearing attempting to conflate compliance filings under FPA section 206 with public utilities' filings under FPA section 205 because both are evaluated based on a just and reasonable standard, *see, e.g.*, WIRES Rehearing Request at 14-15, incorrectly blur the lines between these two distinct statutory provisions.

[179] *See, e.g.*, *PJM Power Providers Grp. v. FERC*, 88 F.4th at 270 n.122 (describing the statutory structure and stating that public utilities may seek, through FPA section 205 filings, to modify rates set by the Commission under FPA section 206).

[180] *See, e.g.*, *Emera Maine*, 854 F.3d at 24 (describing this division, where FPA section 205 is intended for the benefit of the utility, but FPA section 206 has a "quite different" purpose of empowering the Commission to modify rates upon complaint or its own initiative, with "entirely different" and "stricter" procedures, such as the burden of proof and required two-step findings under FPA section 206 (quotation marks and citations omitted)).

54. Nor does the precedent that the rehearing requests rely on[181] to claim that Order No. 1920-A unlawfully intrudes on public utilities' FPA section 205 filing rights support this argument.[182] These cases do not address the context—applicable here—of how the Commission may exercise its authority, under FPA section 206, to determine the just and reasonable replacement rate, including how or from whom it obtains views concerning the replacement rate or which replacement rate it may determine and fix. Rather, they arise in proceedings under different statutory provisions—particularly including FPA section 205 and the parallel context of NGA section 4[183]—as discussed in greater detail below. As a result, none of these cases support the conclusion that the Commission intrudes on FPA section 205 when it exercises its authority under FPA section 206 by requiring that public utilities attach to their compliance filings Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated information or by potentially adopting that agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in determining the replacement rate.

[181] *See, e.g.*, *Atlantic City I*, 295 F.3d at 9-11; *Atlantic City II*, 329 F.3d at 858-59; *NRG Power Mktg.*, 862 F.3d at 114; *Western Resources*, 9 F.3d at 1578; *Massachusetts Department of Public Utilities*, 729 F.2d at 886-88.

[182] *See supra* P 33 (summarizing the arguments by rehearing petitioners asserting that Order No. 1920-A is contrary to judicial precedent relating to public utilities' FPA section 205 filing rights).

[183] 15 U.S.C. 717c.

55. *Atlantic City I* provides a straightforward example of this distinction. The D.C. Circuit there rebuffed a Commission attempt, under FPA section 205,[184] to require that public utilities cede to an ISO their FPA section 205 right to make unilateral changes in rate design, terms or conditions of service such that "only the ISO could propose changes in rate design."[185] The court held that the Commission "lacks the authority to require the petitioners to cede their right under [FPA] section 205 . . . to file changes in rate design with the Commission,"[186] explaining that the Commission was "attempting to deny the utility petitioners the very statutory rights given to them by Congress."[187] Here, by contrast, public utilities retain all of their rights to file proposed rate changes under FPA section 205. Order No. 1920-A's approach to cost allocation in compliance filings, under which transmission providers must attach or include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated material in transmission providers' compliance filings and the Commission may consider and adopt Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, is

[184] 16 U.S.C. 824d.

[185] *Atlantic City I*, 295 F.3d at 7; *see id.* at 9 ("FERC disapproved this sharing arrangement and directed the utility petitioners to give up all authority to make unilateral changes to rate design.").

[186] *Id.* at 11.

[187] *Id.* at 9.

pursuant to the Commission's authority to set a replacement rate in FPA section 206 proceedings.[188]

56. Other cases that the rehearing requests rely on are similarly inapposite because they rejected attempts by the Commission or its predecessor, the Federal Power Commission (FPC), to modify public utilities' FPA section 205 filings or natural gas companies' NGA section 4 filings, without first exercising its authority and carrying its burden under FPA section 206 or NGA section 5, as appropriate.[189] Also distinguishable are cases involving Commission attempts—in NGA section 4 proceedings—to require that natural gas companies refile their rates at regular intervals, rather than the

[188] *Atlantic City II* is inapposite for the same reason, as that decision involved a petition to enforce the mandate of *Atlantic City I* where the Commission "rather than simply vacating the offending portions of its prior order . . . commanded the utilities comprising the ISO to relitigate before it the very issues upon which they had theretofore prevailed before th[e] court." *Atlantic City II*, 329 F.3d at 858; *see also id.* at 859 ("[W]e reaffirm and clarify our prior decision that [the Commission] has no jurisdiction to enter limitations requiring utilities to surrender their rights under [section] 205 of the FPA to make filings to initiate rate changes.").

[189] *See NRG Power Mktg.*, 862 F.3d at 110, 114-17 & n.2 (explaining that, in FPA section 205 proceedings, the Commission may not unilaterally impose a new rate scheme of its own making without the consent of the utility, but that it "may unilaterally impose a new rate scheme on a utility or [RTO] only under a different provision of the Act[,][FPA section 206,]" which was not "the basis for [the Commission's] decision in this case"); *Western Resources*, 9 F.3d at 1577-79 ("After careful consideration of the statutory framework, we cannot accept the Commission's argument that [NGA section] 4 permits it to approve any rate, no matter how materially different from that proposed by the pipeline, so long as it can be viewed as a 'part' of the original request."); *Louisiana v. FPC*, 503 F.2d at 861-62 ("The difficulty is this: FPC approved the interim four-level plan as 'just and reasonable,' and in the next breath it ordered a new, three-level plan to take its place.").

Commission employing its NGA section 5[190] authority to review existing rates.[191] Again, none of these cases address the circumstances presented here, where the Commission has invoked its FPA section 206 authority, made findings that existing practices do not meet the statutory standard, and then further exercised its authority to determine and fix the replacement rate.

57. *Massachusetts Department of Public Utilities* also does not support rehearing petitioners' arguments. In that case, the D.C. Circuit held that the Commission correctly concluded that Massachusetts could not compel a public utility to exercise its FPA section 205 rights to change its Commission-jurisdictional rates.[192] The court there described the "procedural dichotomy" reflected in FPA sections 205 and 206.[193] It explained that Massachusetts's argument that it could compel a public utility to make FPA section 205 rate changes "would prevent the utility from choosing among reasonable rate-practice alternatives."[194] By contrast, the Commission's view was "more consistent with the purposes of the entire procedural scheme" in that it allows the utility's filed rate to remain in effect absent a finding that the rate is unjust, unreasonable, or unduly

[190] 15 U.S.C. 717d.

[191] *See, e.g.*, *Consumers Energy Co. v. FERC*, 226 F.3d 777, 780–81 (6th Cir. 2000); *NYPSC*, 866 F.2d 487, 488–92 (D.C. Cir. 1989).

[192] *Massachusetts Department of Public Utilities*, 729 F.2d at 886-87.

[193] *Id.* at 886-88.

[194] *Id.* at 888.

discriminatory or preferential and allows the utility to change its rate so long as the utility can prove the proposed change is reasonable.[195] This same "procedural dichotomy" supports the lawfulness of Order No. 1920-A; public utilities are not exercising (or being compelled to exercise) their FPA section 205 filing rights. Rather, the Commission has made the requisite findings to support the exercise of its own authority under FPA section 206—a posture that the court in *Massachusetts Department of Public Utilities* differentiated[196]—and the compliance filings that Order Nos. 1920 and 1920-A require and the subsequent fixing of the replacement rate by order occurs under that authority, not FPA section 205.

### (b) Inclusion of Relevant State Entities' Agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in Transmission Providers' Compliance Filings

58. As explained above, Order No. 1920-A's compliance process with respect to cost allocation does not infringe on or encumber transmission providers' FPA section 205 filing rights, as a matter of statutory text, structure, and applicable precedent.

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[195] *Id.*; *see id.* (explaining further that "the net effect of accepting Massachusetts' argument is to allow a state to do what FERC itself cannot, namely, to change an *inter*state rate practice that FERC has not found unreasonable" and also identifying pragmatic considerations relating to the availability of refunds under FPA section 205 and concerns of "confusion, possibly chaos" that could result if states attempted to require conflicting changes); 16 U.S.C. 824e(a).

[196] *Massachusetts Department of Public Utilities*, 729 F.2d at 866-88 (contrasting the two procedural "tracks" under which rates are regulated in FPA sections 205 and 206).

Specifically, the compliance process requirement that transmission providers include in their transmittals or attach to their Order No. 1920 regional transmission planning and cost allocation compliance filings Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process does not infringe or encumber transmission providers' FPA section 205 filing rights. We address in additional detail here certain of the arguments raised on rehearing challenging this requirement.

59. We disagree with rehearing petitioners' claims that requiring transmission providers to include or attach these materials in transmission providers' FPA section 206 compliance filings in response to Order Nos. 1920 and 1920-A constitutes a "filing" requirement under FPA section 205, requires transmission providers to "cede" FPA section 205 filing rights or encumbers those rights, or grants such filing rights to Relevant State Entities. The Commission required only that transmission providers include this material in their FPA section 206 compliance filings, either in the transmittal or an attachment thereto.[197] The Commission did not require transmission providers to independently characterize this material.[198] The Commission was further clear that "the transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments."[199]

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[197] Order No. 1920-A, 189 FERC ¶ 61,126 at P 651.

[198] *Id.* P 655.

[199] *Id.* P 654 n.1651 ("The requirement to include Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method and/or State Agreement

Put in practical terms, in Order No. 1920-A, the Commission requires nothing more from transmission providers than attaching one or more additional documents, produced by parties other than transmission providers, to a compliance filing made under FPA section 206, to assist in building the record for the Commission's exercise of its own authority to determine and fix the just and reasonable rate under that statutory provision, as well as monitoring compliance with the requirements related to the Engagement Period and efficiently considering the views of both Relevant State Entities and transmission providers.[200] Furthermore, this is a one-time filing requirement associated with this FPA section 206 proceeding—not an ongoing obligation affecting any future filings by

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Process as an addition to the compliance filing does not constitute a 'proposal' from the transmission provider.").

[200] FPA section 206 does not mandate a specific process through which the Commission chooses to build the record to determine and fix the replacement rate; rather, FPA section 206 merely requires a hearing prior to finding the existing rate unjust and reasonable, and then empowers the Commission to determine and fix the replacement rate by order. *See* 16 U.S.C. 824e; *see also Pension Ben. Guar. Corp. v. LTV Corp.*, 496 U.S. 633, 653, 655-56 (1990) (holding that when the Due Process Clause is not implicated and an agency's governing statute contains no specific procedural mandates, the APA establishes the maximum procedural requirements a reviewing court may impose on agencies); *Vermont Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 435 U.S. 519, 524 (1978) ("Even apart from the [APA,] this Court has for more than four decades emphasized that the formulation of procedures was basically to be left within the discretion of the agencies to which Congress had confided the responsibility for substantive judgments."); *FPC v. Transcont'l Gas Pipe Line Corp.*, 423 U.S. 326, 333 (1976); *Towns of Concord, Norwood, & Wellesley, Mass. v. FERC*, No. 90–1179, 1991 WL 17224, at *3 (D.C. Cir. 1991) (noting "the Commission's broad authority to establish its own rules of procedure and structure its own methods of inquiry"); 5 U.S.C. 706(2)(D) (permitting courts to hold unlawful and set aside action found to be "without observance of procedure *required by law*" (emphasis added)).

transmission providers under section 205 or any other section of the FPA.[201] And where transmission providers' FPA section 205 rights are at stake, Order No. 1920-A does not include these same requirements.[202]

60. Arguments asserting that the Commission has offered only a "hollow" explanation for this requirement, resting on "empty formalisms,"[203] wrongly conflate the two distinct procedural postures and authorities set forth in FPA sections 205 and 206. The fact that a "compliance filing submitted pursuant to FPA section 206 [as required by Order Nos. 1920 and 1920-A] is not an FPA section 205 filing"[204] carries legal consequences. Moreover, as the Commission explained, the requirement to include materials from Relevant State Entities in the context of this FPA section 206 compliance filing "does not constitute a 'proposal' from the transmission provider"[205] and transmission providers remain free to present whatever proposal they desire (and believe is compliant with the requirements of Order Nos. 1920 and 1920-A). Furthermore, transmission providers retain their full and exclusive discretion as to whether to file—or not file—proposed changes to Long-Term Regional Transmission Cost Allocation Method(s) and/or State

[201] Order No. 1920-A, 189 FERC ¶ 61,126 at P 651.

[202] *See infra* P 118.

[203] MISO TOs Rehearing Request at 19-20; *see also* WIRES Rehearing Request at 13; SPP TOs Rehearing Request at 4-5; EEI Rehearing Request at 8-9.

[204] Order No. 1920-A, 189 FERC ¶ 61,126 at P 652.

[205] *Id.* P 654 n.1651

Agreement Process under FPA section 205. Transmission providers continue to be able to fully participate in the FPA section 206 compliance process, their FPA section 205 rights are not implicated in this process, and FPA section 206 does not constrain the Commission, as it effectuates its own authority under that section, from requiring transmission providers to include information from Relevant State Entities in transmission providers' compliance filings to assist the Commission in setting the just and reasonable rate.

61. SPP TOs' argument that "[t]he Commission previously rejected attempts to use compliance filings to bypass the FPA's filing requirements" and cannot "'circumvent the notice and filing requirements of FPA sections 205 and 206'"[206] is immaterial because Order No. 1920-A does not have these effects—no notice and filing requirements are "bypassed," and no filings under FPA section 205 are required at all. Rather, Order No. 1920-A's approach to cost allocation in the required compliance filings is a proper exercise of the Commission's authority under FPA section 206. For the same reason, we disagree with SPP TOs' assertion that Order No. 1920-A raises a "major question" because it attempts to weaken FPA sections 205 and 206's statutory constraints:[207] Order No. 1920-A is a clear and unequivocal application of the Commission's authority under FPA section 206.

[206] SPP TOs Rehearing Request at 15 & nn.37-38 (quoting *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,083 at P 29).

[207] *Id.* at 17-18.

62. We similarly disagree with SPP TOs' claim that Order No. 1920-A sets a precedent in which, "in a future section 206 complaint proceeding, the Commission could authorize states or other favored parties to include their preferred alternative remedies in other parties' compliance filings without first having to make the first step showings under FPA section 206 that are normally required."[208] The Commission considers compliance filings in FPA section 206 rulemaking proceedings only after it makes a first-step determination that existing rates are unjust, unreasonable, or unduly discriminatory or preferential,[209] as it did in Order No. 1920. Once such a finding is made, the Commission determines and fixes the replacement rate, including through the use of compliance filings.[210]

63. Indicated PJM TOs claim that Order No. 1920-A intrudes into transmission providers' decision making processes by requiring that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation

[208] *Id.* at 15.

[209] 16 U.S.C. 824e(a); *see, e.g.*, *Emera Maine*, 854 F.3d at 24 (holding that "unlike section 205, section 206 mandates a two-step procedure that requires FERC to make an explicit finding that the existing rate is unlawful before setting a new rate").

[210] In a complaint proceeding under FPA section 206, the burden of proof to make this first prong showing is on the complainant, *see id.* 824e(b), but once that showing is made, the replacement rate is determined and fixed by the Commission, *see id.* 824e(a); *see also supra* PP 51 (discussing that the Commission is not, under the FPA, constrained to consider proposals only from particular entities in receiving compliance filings); *infra* PP 86-87 (discussing the Commission's ordinary practice of accepting the compliant, just and reasonable proposal of the public utility and its reasons for taking a different approach with respect to cost allocation under Order No. 1920-A).

Method(s) and/or State Agreement Process in transmission providers' compliance filings.[211] We disagree, however, with the factual premise of this argument—that the requirement to include the Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings changes transmission providers' decision-making process as to what proposal transmission providers choose to make in their compliance filing.[212] Regardless of Order No. 1920-A's filing requirement, transmission providers will need to decide whether to adopt Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, or file a different proposal. And if transmission providers decide to file a different proposal, the requirement to simply include or attach, without characterization, Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated information received from Relevant State Entities need not involve deliberation. In short, the Commission is not regulating transmission providers' decision as to what proposal they make on compliance.[213]

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[211] Indicated PJM TOs Rehearing Request at 12-15.

[212] *See id.* at 12-13.

[213] For this reason, Indicated PJM TOs' discussion of the applicability of precedent relating to RTO governance, *see* Indicated PJM TOs Rehearing Request at 15 & n.50, is mistaken and beside the point. We further find that the Commission's regulation of cost allocation methods for Long-Term Regional Transmission Facilities as practices directly affecting Commission-jurisdictional rates falls well within its authority pursuant to *EPSA*, 577 U.S. at 278. Moreover, *CAISO*, in which the court found that a Commission attempt to order a public utility to replace its governing board exceeded the Commission's authority, 372 F.3d at 398, 403, bears no resemblance whatsoever to the facts before us

64. Indicated PJM TOs' argument is also incorrect for other reasons. This argument is further premised on an alleged intrusion on public utilities' "internal decisions on whether to submit a filing *under section 205 of the FPA* and the content of that filing."[214] But, as discussed above, compliance filings are not submitted under FPA section 205. The compliance filing at issue here is a one-time requirement under FPA section 206. So the premise of this argument is also mistaken as a matter of law and fact.

65. EEI, SPP TOs, and WIRES each argue that there are other avenues (e.g., protests) for parties to be heard with respect to cost allocation, such that allegedly infringing on transmission providers' FPA section 205 rights by requiring inclusion of Relevant State Entities' materials in transmission provider's compliance filings is not necessary or justified.[215] For the most part, these arguments appear to be claims that the Commission's decision on this point was arbitrary and capricious or that the Commission should have adopted a different approach.[216] At times, however, rehearing petitioners

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here, given that the Commission is in no way regulating transmission providers decision-making process or governance structure. Indeed, we note that Indicated PJM TOs' argument proves too much: every time the Commission directs a public utility to make a compliance filing, it requires that the utility make decisions as to what proposal to adopt.

[214] Indicated PJM TOs Rehearing Request at 6-7 (emphasis added); *see also id.* at 2-3; *id.* at 14 (citing *Atlantic City I*, which addressed FPA section 205 rights, and referring to the "passive" role of the Commission, which pertains under FPA section 205).

[215] *See* EEI Rehearing Request at 9-10, 12; SPP TOs Rehearing Request at 15-18; WIRES Rehearing Request at 14.

[216] *See infra* PP 78-80 (addressing these arguments).

link these arguments to their claims that the Commission has afforded Relevant State Entities rights not found in the FPA.[217] We reject these arguments as inconsistent with the statutory text and structure, as well as applicable precedent. Although protests are one way that other entities can be heard, the FPA does not limit the Commission's ability to determine how to build the record when determining and fixing an appropriate replacement rate under FPA section 206.[218]

### (c) Commission Consideration of Relevant State Entities' Agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process

66. The above discussion of the statutory text, structure, and precedent rebuts the core of the challenges to the Commission's determination that it will "consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission providers' proposal—when setting the replacement rate."[219] We address in

[217] *See, e.g.*, EEI Rehearing Request at 9 (arguing that the Commission "goes beyond its authority under the FPA" and that the proper method for submitting an alternative to a replacement rate proposed by a public utility on compliance is to file a protest); SPP TOs Rehearing Request at 17-18 ("The fact that states 'are unable to file cost allocation methods themselves' and must instead either comment on transmission providers' proposals or file section 206 complaints is exactly what the FPA requires." (quoting Order No. 1920-A, 189 FERC ¶ 61,126 at P 645)); WIRES Rehearing Request at 11, 14 (advancing this argument in contending the Commission does not have statutory authority to require a public utility to file another entity's rate proposal).

[218] *See supra* PP 51-52, 59.

[219] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659.

additional detail certain of the specific arguments raised on rehearing challenging Order No. 1920-A in this respect.

67. We continue to conclude that "the Commission need only select a replacement rate that complies with the final rule and that is adequately supported in the record, and then intelligibly explain the reasons for its choice."[220] Claims that Order No. 1920-A distorts the statutory scheme by "elevating" Relevant State Entities to the equivalent of public utilities by requiring that their agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process be included in the compliance filing, which will be assessed under the same just and reasonable standard as articulated in FPA section 205,[221] are unpersuasive. As discussed above, FPA section 206 does not specify that the Commission may only consider public utilities' proposals for a replacement rate; rather, FPA section 206 merely requires a hearing prior to finding the existing rate unjust and reasonable, and then empowers the Commission to determine and fix the replacement rate by order.[222] In fact, the D.C. Circuit has explained that the Commission is not required to await public utilities' proposals on compliance at all but may instead determine and fix the replacement rate coincident with the finding under the first prong of FPA section 206 that the existing rate is unjust and unreasonable.[223] And

[220] *Id*. P 658 (citing *Entergy*, 40 F.4th at 701-02).

[221] *See, e.g.*, SPP TOs Rehearing Request at 13-14.

[222] *See supra* P 51.

[223] *See Electrical District*, 774 F.2d at 494; *Kern River Gas Transmission Co.*, 133 FERC ¶ 61,162 at PP 21-22 ("[A]s an alternative to waiting for the pipeline to

while the Commission has typically adopted public utilities' compliant just and reasonable proposals for the replacement rate without considering alternate proposals by other entities, FPA section 206 does not prevent the Commission from taking a different approach in a specific rulemaking proceeding. Rather, and as discussed further below,[224] where the Commission has adopted transmission providers' proposals on compliance where it finds them compliant with the requirements of the final rule, it has done so based on pragmatic considerations and pursuant to its authority and discretion to determine and fix a just and reasonable rate.[225]

68. Relatedly, MISO TOs misunderstand Order No. 1920-A in contending that the Commission has ascribed "heightened importance" to state-developed cost allocation methods in the context of planning to meet Long-Term Transmission Needs, such that the Commission will be particularly likely to accept Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement

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calculate the rates in a compliance filing, the Commission may calculate and fix the rate itself in the initial order.").

[224] *See infra* PP 71, 86-87.

[225] *See, e.g.*, *Entergy*, 40 F.4th at 701–02 ("[A]t bottom, Petitioners simply argue that, in its view, a better method exists. But [the Commission] is not required to choose the best solution, only a reasonable one." (quotation marks and citation omitted)); *Duke Energy Trading & Mktg., L.L.C. v. FERC*, 315 F.3d 377, 382 (D.C. Cir. 2003) ("[T]here may be a number of different potential rates all of which are just and reasonable."); *Kern River*, 142 FERC ¶ 61,132 at P 37 ("Here, the Commission is acting under NGA section 5, not section 4. However, just as there may be several just and reasonable rates, terms, or conditions which a pipeline may propose in a section 4 proceeding, there may be several just and reasonable rates, terms or conditions which the Commission may adopt as a just and reasonable remedy in a section 5 proceeding.").

Process rather than those of transmission providers.[226] Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes take on heightened importance in relation to other commenters' views, not in relation to transmission providers' proposals for a replacement rate in transmission providers' compliance filings. Further, MISO TOs' argument disregards the Commission's explanation that "the Commission will consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate."[227] The Commission did not state that it was adopting any generic or *per se* preference for Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. Rather, the Commission provided that it will make determinations as to the appropriate replacement rate on a case-by-case basis, based on the entire record and consistent with the Commission's statutory authority and discretion to determine and fix the replacement rate.[228] And, consistent with the

[226] *See, e.g.*, MISO TOs Rehearing Request at 24-25, 33-37 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 659).

[227] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659; *see also id.* (explaining that the Commission was "not required to accept a cost allocation proposal from a transmission provider simply because it may comply with Order No. 1920" but could, instead, "adopt any cost allocation method proposed by Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920").

[228] *See id*. P 658 (explaining how the Commission will consider replacement rate proposals) (citing 16 U.S.C. 824e, 825*l*(b)).

discussion herein, nothing prevents the Commission from determining and fixing the replacement rate of its choosing, including choosing the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, pursuant to FPA section 206, so long as it is consistent with the final rule, adequately supported in the record, and the Commission adequately explains the reason for its choice.

69. MISO TOs claim that "[i]f the Commission accepts the Relevant State Entities' Cost Allocation Method over the transmission provider's method . . . the Commission has subverted future FPA section 205 filings related to that rate scheme in a manner that disfavors the transmission provider's FPA section 205 proposals."[229] Although MISO TOs do not sufficiently explain this specific argument,[230] namely by indicating how they believe the Commission is "subverting" future FPA section 205 filings, this argument again appears to ascribe effects to Order No. 1920-A that it does not have, which we have already addressed. Irrespective of the replacement rate that the Commission sets under FPA section 206, the Commission will assess transmission providers' future FPA section 205 filings according to the statutory standard prescribed by the FPA for such filings. Nothing in Order No. 1920-A "disfavors" or "subvert[s]" those hypothetical

[229] MISO TOs Rehearing Request at 24-25.

[230] A rehearing request must set forth with specificity the grounds on which the request is based. 16 U.S.C. 825*l*(a); 18 CFR 385.713(c)(2) (2024); *see ZEP Grand Prairie Wind, LLC*, 183 FERC ¶ 61,150, at P 10 (2023); *Ind. Util. Regul. Comm'n v. FERC*, 668 F.3d 735, 738-40 (D.C. Cir. 2012).

future filings.[231] Moreover, any challenges related to the Commission's treatment of such future FPA section 205 filings can be raised when those filings are made.

70. We find unpersuasive Indicated PJM TOs' and SPP TOs' arguments that *Entergy* is inapposite to Order No. 1920-A because the Commission in that case first rejected MISO's compliance filing before selecting a different replacement rate.[232] First, the Commission's determination that it may, in compliance proceedings, consider and set as the replacement rate Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process is consistent with both the text and structure of the FPA, for the reasons already discussed.[233] Second, *Entergy* supports this conclusion because it reflects that the Commission, when addressing compliance filings in FPA section 206 proceedings, is not required to adopt a replacement rate proposed by public utilities,[234] but instead may determine and fix any

[231] Challenges to the Commission's treatment of those potential filings are not before us at this time.

[232] *See* Indicated PJM TOs Rehearing Request at 22-23; SPP TOs Rehearing Request at 18-19 n.49.

[233] *See supra* PP 48-53.

[234] In other words, if compliance filings were subject to the requirements of FPA section 205, under which the Commission plays a passive role, once the Commission rejected MISO's proposal in *Entergy* it would not have been empowered to itself fashion a different rate. *Entergy* reflects that this is not the case, as the Commission itself fashioned the replacement rate and the court upheld this result. *See Entergy*, 40 F.4th at 701-02.

just and reasonable replacement rate of its choosing.[235] Third, Indicated PJM TOs and SPP TOs misconstrue *Entergy* as reflecting a requirement that the Commission must first reject a public utility's proposal on compliance before adopting a different replacement rate. That the Commission in that case elected to first consider and reject MISO's proposal[236] before selecting a different replacement rate does not demonstrate that it was legally required to do so—and nothing in *Entergy* holds to the contrary.[237]

71. We are also not convinced by Indicated PJM TOs' contention that the statutory structure of FPA sections 205 and 206 mandates a preference for the public utility's proposal on compliance.[238] Although the Commission has historically identified prudential and policy reasons for adopting public utilities' proposals in compliance

[235] *See id.* (noting that the Commission "is not required to choose the best solution, only a reasonable one" (citations omitted)).

[236] The approach in *Entergy* was consistent with the Commission's general practice with respect to compliance filings under FPA section 206 by public utilities, but, as we have explained above, this practice is not a statutory or legal requirement under FPA section 206.

[237] Contrary to SPP TOs' contention that the Commission erroneously relied on certain cases that do not support its approach, *see* SPP TOs Rehearing Request at 16-17, the Commission cited these cases in "recogni[tion]" of the Commission's typical practice that it "generally does not consider alternate compliance proposals other than those filed by the relevant public utility (here, the transmission provider)," before then explaining why it was not adopting that practice in Order No. 1920-A with respect to these cost allocation proposals. Order No. 1920-A, 189 FERC ¶ 61,126 at P 659; *see F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. at 515 ("To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position." (emphasis in original)).

[238] *See* Indicated PJM TOs Rehearing Request at 17-18, 20.

filings if they are compliant with the requirements of a final rule issued pursuant to FPA section 206,[239] these prudential and policy reasons are not statutory commands.[240] Interpreting the FPA as Indicated PJM TOs urge renders meaningless this aspect of the statutory divide of FPA sections 205 and section 206 and would impermissibly convert the Commission's statutory authority to determine the replacement rate into a substantive statutory right for the public utilities.

72. Indicated PJM TOs and WIRES are similarly incorrect in arguing that the Commission is limited to considering whether the rate submitted by the public utility on compliance is just and reasonable because the Commission failed to prescribe a specific replacement rate in Order No. 1920-A.[241] Consistent with the D.C. Circuit's holding in

[239] *See, e.g.*, *Kern River*, 142 FERC ¶ 61,132 at P 37 (noting that "[i]f the pipeline supports one such just and reasonable remedy, the Commission finds that adopting the pipeline's remedy, in preference to other possible remedies, properly recognizes the NGA's policy of giving pipelines the primary initiative to establish their rates, terms, and conditions of service" but also recognizing that "there may be several just and reasonable rates, terms or conditions which the Commission may adopt as a just and reasonable remedy in [an NGA] section 5 proceeding"); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 at P 117 n.175 ("Because PJM may make a section 205 filing to revise these [OATT] provisions, we find it reasonable to accept PJM's proposal over alternatives if PJM's proposal is just and reasonable.").

[240] *See* 16 U.S.C. 824e(a); *Electrical District*, 774 F.2d at 492. Reinforcing this conclusion, the D.C. Circuit has explained that the Commission is not required to await public utilities' proposals on compliance at all but may instead set the replacement rate. *See Electrical District*, 774 F.2d at 494; *Kern River Gas Transmission Co.*, 133 FERC ¶ 61,162 at PP 21-22 ("[A]s an alternative to waiting for the pipeline to calculate the rates in a compliance filing, the Commission may calculate and fix the rate itself in the initial order.").

[241] Indicated PJM TOs Rehearing Request at 28; *see also, e.g.*, *id.* at 3-4, 5, 7-8; WIRES Rehearing Request at 10-11.

*Electrical District*, the Commission is not "obligat[ed] to end an unlawful rate from the moment it finds unlawfulness" but rather may "tak[e] time for further deliberations necessary to determine what the precise terms of [the replacement rate] should be."[242] The "not at all ambiguous" procedures set forth in FPA section 206 establish that after finding existing rates are unjust, unreasonable, or unduly discriminatory or preferential "'the Commission shall determine the just and reasonable rate . . . *to be thereafter observed and in force, and shall fix the same by order*.'"[243] Claims that the Commission somehow in Order No. 1920 or 1920-A forfeited to transmission providers the responsibility—assigned to the Commission by the statute's plain text— to fix the replacement rate, consistent with the requirements of those orders, are not grounded in the statutory text or structure, and are contrary to precedent.[244]

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[242] *Electrical District*, 774 F.2d at 492; *see also Entergy*, 40 F.4th at 701-02 (affirming order in which the Commission, after rejecting MISO's compliance filings, subsequently determined the replacement rate on its own initiative, under FPA section 206).

[243] *Electrical District*, 774 F.2d at 492 (quoting FPA section 206(a), 16 U.S.C. 824e(a); emphasis in original).

[244] Contrary to Indicated PJM TOs' argument, *see* Indicated PJM TOs Rehearing Request at 27 n.102, the Commission's decision in *Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,165 (2009) does not suggest that the Commission forwent the opportunity to establish a specific replacement rate. Rather, the discussion in that case addressed the point at which a sufficient degree of specificity has been provided such that a rate can be deemed fixed for purposes of a particular effective date, *id.* PP 21-26, and—in fact—is consistent with viewing the Commission's authority under FPA section 206 as part of an ongoing process until the replacement rate is fixed.

### b. Compliance with the APA

#### i. Rehearing Requests

73. Several petitioners argue that the Commission failed to engage in reasoned decision-making as required by the Administrative Procedure Act (APA) in adopting the requirement that transmission providers include in the transmittal or as an attachment to their compliance filings any Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed to by Relevant State Entities as well as any and all supporting evidence and/or justification related to such method(s) and/or process.[245] MISO TOs, Indicated PJM TOs, SPP TOs, and EEI argue that the Commission failed to explain why states did not already have adequate opportunities to provide input to cost allocation through previously existing processes—generally connecting these arguments to their view that the compliance filing requirements in Order No. 1920-A are inconsistent with FPA section 205.[246] MISO TOs and SPP TOs argue

[245] Indicated PJM TOs Rehearing Request at 8 (citing *Mayor of Balt. v. Azar*, 973 F.3d 258, 275 (4th Cir. 2020) (other citations omitted)); MISO TOs Rehearing Request at 20-21 (citing 5 U.S.C. § 706 (other citations omitted)); SPP TOs Rehearing Request at 2 (citing 5 U.S.C. § 706(2)).

[246] MISO TOs Rehearing Request at 8-9, 20-22 (arguing that the Commission provides notice and comment review of compliance filings, through Commission Rules of Practice and Procedure 211 and 214, which is "reasonable and more statutorily aligned" than the approach adopted in Order No. 1920-A); Indicated PJM TOs Rehearing Request at 8 ("The Commission made no finding and there is no substantial evidence that the Commission would not have been able to consider those proposals or that the [Relevant State Entities] would not have been able to submit their proposals to the Commission or were in any way impeded from doing so."); *id.* at 12 n.35, 32-33; SPP TOs Rehearing Request at 29 (arguing that the importance the Commission ascribes to state perspectives reflects that state views would be taken seriously if presented through other means, such that there is no need for additional avenues for state participation

that Order No. 1920-A's compliance filing requirements are inconsistent with the Commission's determination that transmission providers have the obligation, subject to Commission oversight, to engage in transmission planning and cost allocation.[247] WIRES argues that the approach the Commission selected in Order No. 1920-A is adversarial, leading to delay and litigation, and that "the record demonstrates that there are other less intrusive means by which states can meaningfully participate in the development of Long-Term Regional [Transmission] Cost Allocation [M]ethods and State Agreement Processes."[248] EEI argues that the Commission's stated justification for requiring transmission providers to include in their compliance filings the preferred approach of Relevant State Entities to cost allocation (i.e., the unique role of Relevant State Entities) does not relate to cost allocation and does not justify infringing on utilities'

through "preferential filing privileges that are not contemplated by the FPA"); EEI Rehearing Request at 9-10 ("After all, state commissions are already afforded special treatment under the Commission's procedural rules because they can intervene in rate proceedings as a matter of right.").

[247] MISO TOs Rehearing Request at 22-23 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 661) ("The Commission fails to explain how it maintains this 'tariff obligation' if it requires transmission providers to subordinate their interests and preferences those of state entities."); SPP TOs Rehearing Request at 14, 29 (similar).

[248] WIRES Rehearing Request at 14, 16-17 (asserting that the same set of facts relied on in Order No. 1920 were used to justify the requirements of Order No. 1920-A, such that "there seems little connection between what are essentially the same facts and the choices made"). WIRES here challenges both the compliance filing requirements, discussed above, and certain consultation requirements set forth by Order No. 1920-A, *see infra* Consultation with Relevant State Entities After the Engagement Period section, as arbitrary and capricious for the same reasons.

FPA filing rights.[249] EEI further argues that the requirement to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings could confuse stakeholders as to which material to provide feedback on—that of the transmission provider or of the Relevant State Entities—and result in stakeholder feedback that is not focused on the transmission provider's proposal.[250]

74. MISO TOs, Indicated PJM TOs, SPP TOs, and EEI all argue that the Commission has departed—without sufficient basis or explanation—from its precedent establishing a preference for accepting the compliant just and reasonable compliance proposals of public utilities (or, in the context of the NGA, natural-gas companies), rather than competing proposals.[251] They assert that this preference is justified (as recognized by

[249] EEI Rehearing Request at 12.

[250] *Id*. at 10.

[251] *See* MISO TOs Rehearing Request at 33-38 (arguing that the Commission failed to provide adequate reasoning to support this decision); Indicated PJM TOs Rehearing Request at 18-20; *id.* at 21 (arguing that "the Commission does not explain how these considerations [that it identified as supporting its approach in Order No. 1920-A] are any different in the planning process under Order No. 1920 and 1920-A than they are in the planning processes under other prior rule changes" such as Order No. 1000); SPP TOs Rehearing Request at 16-17; *id.* at 30 (arguing that this departure from the Commission's approach in other contexts is arbitrary and capricious); EEI Rehearing Request at 10-11. These petitioners cite several Commission decisions reflecting this preference, *see, e.g.*, *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 115 n.124; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084, at P 21 n.18 (2008); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 85 (2006); *Kern River Gas Transmission Co.*, Opinion No. 486-F, 142 FERC ¶ 61,132 at P 37 & n.50 ; *ANR Pipeline Co.*, 109 FERC ¶ 61,138, at P 28 (2004), *order on reh'g*, 111 FERC ¶ 61,113, at P 19 (2005), as well as certain judicial decisions, *see, e.g.*, *Emera Maine*, 854 F.3d at 674; *Pub. Serv. Comm'n of N.Y. v. FERC*, 642 F.2d 1335, 1343-44 (D.C. Cir.

Commission precedent) because public utilities have the primary initiative to set their rates, terms, and conditions of service and because, should the Commission adopt a compliance proposal from an entity other than the public utility, the public utility could immediately refile its own proposal under FPA section 205.[252]

75. SPP TOs contend that the Commission improperly imposed different requirements on compliance proposals addressing cost allocation for Relevant State Entities versus transmission providers.[253] Specifically, SPP TOs state that compliance filings by transmission providers must comply with five of Order No. 1000's six regional cost allocation principles, but Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process must merely comply with the cost-causation principle and any other legal requirements for cost allocation.[254] SPP TOs aver that it is unclear how the Commission will choose between competing replacement rate proposals given that they are subject to different criteria, and assert that the Commission will struggle to explain a decision to adopt, as the

1980); *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 514 (D.C. Cir. 1985); *Consol. Edison Co. v. FERC*, 165 F.3d 992, 1000 (D.C. Cir. 1999).

[252] *See, e.g.*, MISO TOs Rehearing Request at 33-35; *id.* at 37-38 (arguing that Order No. 1920-A creates a layer of bureaucratic delay); Indicated PJM TOs Rehearing Request at 18-21.

[253] *See* SPP TOs Rehearing Request at 20-21.

[254] *See id.*; *see also id.* at 7 (arguing that Order No. 1920-A violates the structure of FPA sections 205 and 206 because it imposes on transmission providers a higher burden than on Relevant State Entities).

replacement rate, Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.[255]

### ii. Commission Determination

76. We disagree with arguments raised on rehearing that the Commission failed to comply with the APA in adopting the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and associated information in their Order No. 1920 regional transmission planning and cost allocation compliance filings.

77. Under the APA, agency action must be upheld unless it is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law.[256] In *South Carolina*, the D.C. Circuit set forth the standard that the Commission must meet in issuing a rule for the court to find that the Commission met its obligations under the APA:

> The Commission must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made. The Commission's factual findings are conclusive if supported by substantial evidence. Substantial evidence is such relevant evidence as a reasonable mind might accept as adequate to support a conclusion, and requires more than a scintilla but less than a preponderance of evidence. When applied to rulemaking proceedings, the substantial evidence test is identical to the familiar arbitrary and capricious standard, which requires the Commission to specify the

[255] *See id*.

[256] 5 U.S.C § 706(2)(A).

> evidence on which it relied and to explain how that evidence supports the conclusion it reached.[257]

78. We disagree with the rehearing petitioners who argue that the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings fails to satisfy these requirements. Specifically, we disagree with the arguments by MISO TOs, Indicated PJM TOs, SPP TOs, and EEI that the Commission failed to explain why states did not already have adequate opportunities to provide input on regional transmission cost allocation issues through previously existing processes. Recognizing the increased importance of state engagement regarding cost allocation for Long-Term Regional Transmission Facilities, the Commission in Order No. 1920 established the Engagement Period and required transmission providers on compliance to explain how they complied with the requirement to provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process that enables meaningful participation by Relevant State Entities.[258] In Order No. 1920-A, the Commission reiterated that it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a

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[257] *South Carolina*, 762 F.3d at 54 (quotation marks omitted) (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); 16 U.S.C. 825*l*(b); *Murray Energy Corp. v. FERC*, 629 F.3d 231, 235 (D.C. Cir. 2011); *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 645 (D.C. Cir. 2010); *Wis. Gas Co. v. FERC*, 770 F.2d 1144, 1156 (D.C. Cir. 1985)).

[258] Order No. 1920, 187 FERC ¶ 61,068 at PP 126, 1354, 1357.

significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes.[259] Consistent with these findings, when the Commission adopted the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, and any information relevant thereto, in their compliance filings, the Commission found that the additional requirement would allow it to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiations that enables meaningful participation by Relevant State Entities during the Engagement Period.[260] The Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed upon by Relevant State Entities during the Engagement Period are thus evidence for compliance purposes that will assist the Commission as it determines and fixes the replacement rate.

79. Moreover, receiving Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, and any information relevant thereto, in tandem with transmission providers' compliance filings is procedurally consistent with the Commission's intention, as stated in Order No. 1920-A, to review the entire record in determining and fixing a replacement rate. We further conclude that, in these circumstances, there is significant administrative efficiency in

[259] Order No. 1920-A, 189 FERC ¶ 61,126 at PP 649, 654-657.

[260] *Id.*

receiving these materials together, as—for instance—it will allow interested stakeholders to comment simultaneously on both transmission providers' proposal and Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. We anticipate that this process will provide the Commission with a more comprehensive, better-developed record for the exercise of its FPA section 206 authority to determine and fix the replacement rate.[261]

80. Rehearing petitioners argue that there are other avenues available for Relevant State Entities to present their views, such as through protests.[262] But the availability of such alternative approaches, and rehearing petitioners' view that they are adequate or preferable, does not render Order No. 1920-A's requirements unjust and unreasonable or arbitrary and capricious.[263] The Commission has adequately explained and supported the approach that it adopted in Order No. 1920-A.

81. We also disagree with MISO TOs' and SPP TOs' arguments that Order No. 1920-A's compliance filing requirements are inconsistent with the Commission's

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[261] *Id.* P 659.

[262] *See, e.g.*, EEI Rehearing Request at 9-10; SPP TOs Rehearing Request at 17-18, 29; WIRES Rehearing Request at 14.

[263] *See, e.g.*, *EPSA*, 577 U.S. at 292 ("A court is not to ask whether a regulatory decision is the best one possible or even whether it is better than the alternatives. Rather, the court must uphold a rule if the agency has 'examine[d] the relevant [considerations] and articulate[d] a satisfactory explanation for its action[,] including a rational connection between the facts found and the choice made.'" (alterations in original) (quoting *State Farm*, 463 U.S. at 43)); *Entergy*, 40 F.4th at 701–02 ("[A]t bottom, Petitioners simply argue that, in its view, a better method exists. But [the Commission] is not required to choose the best solution, only a reasonable one." (quotation marks and citation omitted)).

determination that transmission providers have the obligation, subject to Commission oversight, to engage in transmission planning and cost allocation. Order No. 1920-A is clear that, as in Order No. 1920, transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments, whether they decide to propose the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process or a different Long-Term Regional Transmission Cost Allocation Method.[264] This requirement therefore does not diminish transmission providers' role in transmission planning and cost allocation matters. Further, Order No. 1920-A retains the Commission's oversight of transmission providers' transmission planning and cost allocation, as the Commission will exercise its authority under FPA section 206 to determine the replacement rate on compliance.[265]

82. We disagree with WIRES that Order No. 1920-A is arbitrary and capricious because, in WIRES' opinion, Order No. 1920-A "adopts an adversarial approach" that is "likely to engender years of costly litigation that would cast a cloud over successfully siting and developing critically needed transmission in a timely manner."[266] To begin

[264] Order No. 1920-A, 189 FERC ¶ 61,126 at P 654 n.1651 ("The requirement to include Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process as an addition to the compliance filing does not constitute a 'proposal' from the transmission provider.").

[265] *Id.* P 659.

[266] WIRES Rehearing Request at 14.

with, as rehearing petitioners recognize,[267] absent Order No. 1920-A's requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings, Relevant State Entities would be able to submit their agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in comments in opposition to transmission providers' compliance filings. Therefore, were a transmission provider to choose not to propose Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance, the proceedings related to the transmission provider's compliance filing could still result in disagreement between the transmission provider and Relevant State Entities, regardless of whether the Commission required transmission providers to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings. However, as discussed above, the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings, as well as any information that Relevant State Entities provide to them regarding the state negotiations during the Engagement Period, will allow the Commission to better evaluate whether transmission providers have complied with Order

[267] *See, e.g.*, EEI Rehearing Request at 9-10; SPP TOs Rehearing Request at 17-18, 29; WIRES Rehearing Request at 14.

No. 1920's requirement to provide a forum for negotiations that enables meaningful participation by Relevant State Entities during the Engagement Period.[268] Moreover, we believe that ensuring that such a forum exists—and verifying compliance with this requirement—is likely to reduce the prospect of disputes over cost allocation methods by ensuring Relevant State Entities' views are considered by transmission providers and therefore that their participation is meaningful.[269] Therefore, on balance, the Commission reasonably required that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings.

83. We also disagree with WIRES' argument that the Commission's adoption of Order No. 1920-A's "compliance mandates" is arbitrary and capricious because the Commission in Order No. 1920-A "defend[ed] its amendments by using the same justification relied upon in Order No. 1920."[270] In Order No. 1920-A, the Commission "weighed [the] competing views" presented by rehearing petitioners and, based upon the substantial evidence it identified in Order No. 1920, concluded that the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional

[268] We note that no rehearing petitioners challenge the requirements of Order Nos. 1920 and 1920-A regarding the Engagement Period.

[269] *E.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 124 ("As the Commission discussed in the NOPR and we continue to find in this final rule, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.").

[270] WIRES Rehearing Request at 15.

Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings is just and reasonable.[271] The Commission further concluded that this and other requirements adopted in Order No. 1920-A strike a reasonable balance between, on the one hand, recognizing the rights and responsibilities of the Commission and transmission providers over regional transmission planning and, on the other, the states' critical interests in the resulting Long-Term Regional Transmission Facilities and how the costs associated with those facilities will be allocated.[272] Therefore, the Commission's decision-making in this regard satisfies the APA.

84. We also are not persuaded by EEI's argument that the unique role of Relevant State Entities does not relate to cost allocation or justify the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings.[273] In Order No. 1920-A, the Commission reiterated that states play a

[271] *See Entergy*, 40 F.4th at 701-02 ("It is not our job to determine that 'FERC made the better call,' rather, our 'important but limited role is to ensure that the Commission engaged in reasoned decisionmaking.'" (quoting *EPSA*, 577 U.S. at 295)). *See also* Order No. 1920-A, 189 FERC ¶ 61,126 at P 649 ("As the Commission recognized in Order No. 1920, and we reiterate in this order, it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes." (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1415)); *id.* P 659 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362-1364, 1404, 1407, 1410-1411, 1415, 1477, 1515).

[272] Order No. 1920-A, 189 FERC ¶ 61,126 at P 660.

[273] *See* EEI Rehearing Request at 12.

unique role in Long-Term Regional Transmission Planning, as their laws, regulations, and policies drive the need for Long-Term Regional Transmission Facilities, and they typically will have responsibility to consider and approve the siting, permitting, and construction of Long-Term Regional Transmission Facilities selected in a regional transmission plan.[274] As such, states affect whether Long-Term Regional Transmission Facilities are timely, efficiently, and cost-effectively developed such that customers actually receive the benefits associated with the selection of more efficient or cost-effective transmission solutions.[275] The effect of Relevant State Entities' decisions on such timely, efficient, and cost-effective development of Long-Term Regional Transmission Facilities directly relates to the allocation of costs for those facilities. It is therefore reasonable to require that transmission providers provide the Commission with any Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process that Relevant State Entities have agreed upon.

85. Further, we disagree with EEI that stakeholders are likely to be confused as to whether they should provide feedback on the transmission provider's proposal or the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process that Relevant State Entities have agreed upon.[276] As the Commission clarified in

[274] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659.

[275] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362-1364, 1404, 1407, 1410-1411, 1415, 1477, 1515).

[276] *See* EEI Rehearing Request at 10.

Order No. 1920-A, any Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed upon by Relevant State Entities and included in a transmission provider's transmittal or as an attachment to its compliance filing does not constitute a proposal from the transmission provider. Furthermore, commenters may provide their support for, or feedback on, either or both the transmission provider's proposal and any Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed upon by Relevant State Entities.

86. We disagree with MISO TOs, Indicated PJM TOs, SPP TOs, and EEI that the Commission departed—without sufficient basis or explanation—from its precedent establishing a preference for accepting compliant, just and reasonable compliance proposals of public utilities rather than competing proposals.[277] The Supreme Court has held that "agency action representing a policy change [need not] be justified by reasons more substantial than those required to adopt a policy in the first instance."[278] Rather, where an agency changes its position, "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates."[279]

[277] *See* MISO TOs Rehearing Request at 33-38; Indicated PJM TOs Rehearing Request at 18-21; SPP TOs Rehearing Request at 16-17, 30; EEI Rehearing Request at 10-11.

[278] *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 514.

[279] *Id.* at 515.

87. Order No. 1920-A satisfies these requirements. First, as explained above,[280] the Commission's typical practice of accepting compliant just and reasonable compliance proposals of public utilities rather than competing proposals is just that: a practice, not a requirement of the FPA. Next, in Order No. 1920-A, the Commission recognized that, while it generally does not consider alternate compliance proposals other than those filed by the relevant public utility,[281] there are "good reasons" for considering Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in addition to transmission providers' proposals here.[282] Specifically, and as discussed: (1) states play a unique role in Long-Term Regional Transmission Planning;[283] (2) states affect whether Long-Term Regional Transmission Facilities are timely, efficiently, and cost-effectively developed;[284] and (3) given the inherent uncertainty involved in planning to meet Long-Term Transmission Needs, state-developed cost allocation methods and State Agreement Processes take on

[280] *See supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods, Statutory Filing Rights Under the FPA section.

[281] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659 (citing *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 at P 117 n.175; *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 115; *ANR Pipeline Co.*, 110 FERC ¶ 61,069 at P 49).

[282] *Id.* P 659.

[283] *Id.*; *supra* P 84.

[284] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362-1364, 1404, 1407, 1410-1411, 1415, 1477, 1515); *supra* P 84.

heightened importance.[285] The Commission thus adequately explained its belief, based on these "good reasons," that considering Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process along with the transmission provider's proposal is not simply warranted, but "better" than considering the transmission provider's proposal alone and to the exclusion of alternatives.[286]

88. We recognize that, even if the Commission adopts Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process as the replacement rate under FPA section 206, transmission providers may subsequently file an FPA section 205 proposal seeking to implement their preferred approach to cost allocation.[287] Nonetheless, we sustain Order No. 1920-A's determination that the Commission will consider the entire record on compliance in selecting the replacement rate and may permissibly adopt Relevant State Entities' agreed-upon approach. While transmission providers' ability to submit an FPA section 205 filing of their own initiative proposing a set of preferred rates is a consideration the Commission has identified as relevant to our typical approach to

[285] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 227).

[286] *FCC v. Fox Television Stations, Inc.*, 556 U.S. at 514-15.

[287] *See* MISO TOs Rehearing Request at 35, 37-38; Indicated PJM TOs Rehearing Request at 20-21.

assessing compliance filings,[288] this consideration—standing alone—cannot render it inherently arbitrary and capricious for the Commission to require, in FPA section 206 proceedings, a replacement rate other than the one proposed by the transmission provider. A contrary conclusion would effectively amend FPA section 206, removing the Commission as the entity that "determine[s] the just and reasonable rate . . . to be thereafter observed and in force."[289] As discussed above, this is not the design Congress enacted.[290]

89. We disagree with SPP TOs' argument that the Commission improperly imposed different requirements on Long-Term Regional Transmission Cost Allocation Methods agreed upon by Relevant State Entities—which need not comply with any of the Order No. 1000 regional cost allocation principles—and Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities do not agree—which must comply with Order No. 1000 regional cost allocation principles (1) through (5).[291] We reiterate that all cost allocation methods must comply with the cost causation principle, as

[288] *See PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 at P 117 n.175 ("Because PJM may make a section 205 filing to revise these Tariff provisions, we find it reasonable to accept PJM's proposal over alternatives if PJM's proposal is just and reasonable.").

[289] 16 U.S.C. 824e(a).

[290] *See supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods, Statutory Filing Rights Under the FPA section.

[291] *See* SPP TOs Rehearing Request at 7, 20-21.

required by the FPA.[292] We also continue to find that although there are different requirements for cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Method that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file, as compared to Long-Term Regional Transmission Cost Allocation Methods to which states do not agree, this distinction is appropriate to afford flexibility in order to encourage their use of these methods, which are likely to facilitate agreement over development of such Long-Term Regional Transmission Facilities and thus facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[293] We further find speculative and disagree with SPP TOs' assertion that the Commission will struggle to explain a decision to adopt Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process as the replacement rate. If the Commission fixes Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process as the replacement rate, the Commission will necessarily and intelligibly explain why that method(s) and/or process complies with the final rule based on support in the record.[294]

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[292] Order No. 1920-A, 189 FERC ¶ 61,126 at P 763 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1305 & n.2786).

[293] Order No. 1920, 187 FERC ¶ 61,068 at P 1477; *see also* Order No. 1920-A, 189 FERC ¶ 61,126 at P 763 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1477).

[294] *See Entergy*, 40 F.4th at 701-02.

### c. Cooperative Federalism

#### i. Rehearing Requests

90. SPP TOs argue that Order No. 1920-A is contrary to the FPA's structure of cooperative federalism because "[t]here is a very real possibility that a proposal could be added to a compliance filing despite one or more of the Relevant State Entities' opposition."[295] In this respect, SPP TOs differentiate Order No. 1920-A from the Commission action at issue in the Supreme Court's decision in *EPSA*, asserting that the Court there upheld the Commission's "treatment of demand response resources in wholesale markets [because it] did not 'negate state decisions' regarding retail demand response programs on the basis that there was a 'veto power . . . granted to the States.'"[296]

#### ii. Commission Determination

91. We are not persuaded by SPP TOs' argument invoking cooperative federalism principles. The Supreme Court in *EPSA* addressed arguments that the Commission's regulation of demand response, pursuant to the Commission's authority over wholesale markets, allegedly intruded on a particular area of reserved state authority over retail

[295] SPP TOs Rehearing Request at 30-31 ("[U]nder Order No. 1920-A, some state policies could be imposed, not only on the transmission provider, but on dissenting states if the Commission used its claimed power to accept favored compliance filings reached through any means other than unanimity."); *see also id.* at 31 ("When the outcome of the Engagement Period process was merely advisory as the Commission originally ordered in Order No. 1920, the methodology developed during the Engagement Period could only be filed with the Commission on compliance if adopted by the transmission provider *as its own*.").

[296] *Id.* (quoting *EPSA*, 577 U.S. at 288).

rates.[297] SPP TOs do not point to a similar alleged intrusion on a particular area of reserved state authority here. Moreover, even in that context where reserved state authority was implicated, *EPSA* did not describe the state veto power afforded in the Commission's order on demand response as "dispositive" as SPP TOs contend,[298] but rather as a "finishing blow . . . [that] removes any conceivable doubt as to [the order's] compliance with [FPA section 201(b)]'s allocation of federal and state authority."[299] In other words, the Court treated the state "veto power" in that case as confirming the Commission's compliance with principles of cooperative federalism, having already discussed at length why the Commission, regulating within the areas of its jurisdiction, was not intruding on state prerogatives.[300] We further note that, in Order No. 1920-A, the Commission explained that it would defer to the Relevant State Entities themselves to determine what constitutes "agreement" on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.[301] Accordingly, we continue to

[297] *See EPSA*, 577 U.S. at 281-82.

[298] SPP TOs Rehearing Request at 31.

[299] *EPSA*, 577 U.S. at 287-88.

[300] *See id.* at 281-87 (concluding the Commission's order was consistent with FPA section 201(b) notwithstanding that it "affects—even substantially—the quantity or terms of retail sales" because it "addresses—and addresses only—transactions occurring on the wholesale market" that are within the Commission's jurisdiction, and the Commission's regulatory justification "are all about, and only about, improving the wholesale market").

[301] Order No. 1920-A, 189 FERC ¶ 61,126 at P 654 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1360).

find that the Commission's approach in Order No. 1920-A is consistent with the division of responsibility set forth in the FPA, consistent with our discussion in Order No. 1920-A.[302]

### d. Sub-Delegation

#### i. Rehearing Requests

92. MISO TOs and SPP TOs assert that the Commission in Order No. 1920-A impermissibly sub-delegated its authority to Relevant State Entities.[303] MISO TOs argue that the Commission is giving Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process "heightened importance" over those of transmission providers, with the effect of permitting Relevant State Entities to set interstate transmission rates.[304] MISO TOs state that statutory authority to determine whether transmission rates are unwarranted or excessive lies with the Commission, under the FPA, and cannot be sub-delegated to state commissions.[305] SPP TOs assert that the Commission "effectively purports to delegate the right to file

[302] *Id.* PP 135-165.

[303] *See* MISO TOs Rehearing Request at 8, 9-10, 38-41; SPP TOs Rehearing Request at 32-34.

[304] MISO TOs Rehearing Request at 38-41 (arguing that the "most reasonable way to interpret the rule is that the Commission is empowering states with such new 'authority,' permitting Relevant State Entities to dictate transmission cost allocation, critically, over the objection of the filing utility itself").

[305] *Id.* at 39-41 (citing Order No. 1920-A, 189 FERC ¶ 61,126 (Christie, Comm'r, concurring at P 3)).

compliance filings—which [is] granted to public utilities under the FPA—to the states," which is impermissible under *Atlantic City I* and other cases, but also not within the set of circumstances in which federal agencies may sub-delegate matters to the states.[306] SPP TOs also assert that under Order No. 1920-A "the Commission will, in practice, show a high degree of deference to alternative state proposals that would be tantamount to a sub-delegation of Commission authority to the states."[307]

### ii. Commission Determination

93. We find arguments that the Commission has unlawfully sub-delegated its authority[308] are incorrect because there is no sub-delegation, impermissible or otherwise, of Commission authority here.[309] Contrary to MISO TOs' and SPP TOs' claims, the Commission has not sub-delegated to states its FPA section 206 authority to determine the replacement rate: the Commission has expressly stated that it will consider the entire

[306] SPP TOs Rehearing Request at 32-33 (citing *U.S. Telecom Ass'n v. FCC*, 359 F.3d 554, 565, 567-68 (D.C. Cir. 2004) (*U.S. Telecom*)).

[307] *Id.* at 33-34.

[308] *See* MISO TOs Rehearing Request at 8, 9-10, 38-41; SPP TOs Rehearing Request at 32-34.

[309] *U.S. Telecom* does not support MISO TOs' or SPP TOs' arguments. There, the FCC had extensively sub-delegated its authority over unbundling of mass market switches to state commissions—indeed, there was no dispute that such a sub-delegation had occurred, with the FCC arguing instead that the sub-delegation was permissible. *See U.S. Telecom*, 359 F.3d at 564-68. Here, by contrast, the compliance process set forth in Order No. 1920-A as to cost allocation provides a vehicle for the receipt of Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and the Commission retains all decision-making authority under FPA section 206 to determine the replacement rate.

record before it and, itself, determine the replacement rate.[310] That the Commission will entertain on compliance Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, *in addition* to any proposals made by transmission providers, and may fix one of those as the replacement rate does not suggest that the Commission has abdicated to states the Commission's clear and exclusive authority to determine and fix the replacement rate under FPA section 206. SPP TOs' argument that the Commission has unlawfully sub-delegated to states the right to make compliance filings, which—SPP TOs claim—is granted solely to public utilities, is also mistaken. As explained above, the compliance process assists the Commission in determining the replacement rate, under FPA section 206. Order No. 1920-A requires that transmission providers—not states—make compliance filings, and sets out the information that transmission providers must include in those filings. Arguments that Order No. 1920-A intrudes on public utilities' rights or unlawfully assigns those rights to Relevant State Entities are incorrect.[311]

[310] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659; *see also supra* P 68 (explaining that the Commission expects to determine the replacement rate on a case-by-case basis, consistent with its authority and discretion to select from the range of just and reasonable replacement rates).

[311] *See supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods, Statutory Filing Rights Under the FPA section.

### e. First Amendment

#### i. Rehearing Requests

94. Indicated PJM TOs argue that the requirement to include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in transmission providers' compliance filings is governmentally compelled speech that violates the First Amendment to the Constitution.[312] Indicated PJM TOs assert that the First Amendment protects the right to petition the government, including through filings with courts and administrative agencies.[313] Indicated PJM TOs contend that the compliance filing requirement violates their rights not to speak by mandating that a public utility present views with which it disagrees when filing its own proposal.[314] Indicated PJM TOs state that the Supreme Court has held that "the government may not require that an entity present views with which it disagrees when it

[312] Indicated PJM TOs Rehearing Request at 29-34 (citing, *inter alia*, *Pac. Gas & Elec. Co. v. Pub. Util. Comm'n of Cal.*, 475 U.S. 1, 12-14 (1986) (*PG&E*)); *cf.* SPP TOs Rehearing Request at 13-14 (arguing that requiring a transmission provider to include Relevant State Entities' information with its own commandeers the transmission provider's compliance filing, citing *PG&E*, 475 U.S. 1).

[313] Indicated PJM TOs Rehearing Request at 29 (citing U.S. Const. amend. I; *E. R.R. Presidents Conf. v. Noerr Motor Freight, Inc.*, 365 U.S. 127, 138 (1961); *Cal. Motor Transp. Co. v. Trucking Unlimited*, 404 U.S. 508, 510 (1972); *White v. Lee*, 227 F.3d 1214, 1231 (9th Cir. 2000)).

[314] *Id.* at 30-32 (citing *PG&E*, 475 U.S. at 12-14; *Moody v. Netchoice, LLC*, 603 U.S. 707, 726-33 (2024); *Wooley v. Maynard*, 430 U.S. 705, 714 (1977); *United States v. United Foods, Inc.*, 533 U.S. 405, 409-10 (2001)).

engages in expressive speech."[315] They compare this case to the Supreme Court's decision in *PG&E*, which overturned a state regulation requiring a utility to include material from a consumer advocacy group in a newsletter regularly included in the utility's billing envelopes expressing the utility's views of energy policy.[316]

95. Indicated PJM TOs state that the Order No. 1920-A compliance filing requirement at issue here would not meet the strict scrutiny standard under the First Amendment, asserting that it is not content neutral because it is "intended to give more weight to the views of [Relevant State Entities] in the Order No. 1920 context than it normally would give in other proceedings" and that there is no compelling government interest justifying the requirement.[317] Indicated PJM TOs also argue that the compliance filing requirement would not survive the intermediate scrutiny standard, stating that it is not narrowly tailored to achieve the Commission's stated interest, and burdens substantially more of transmission providers' First Amendment petitioning right than necessary to advance that interest.[318]

96. Indicated PJM TOs assert that the limitations the Commission imposed on the compliance filing requirement—that transmission providers do not need to separately

[315] *Id.* at 30 (citing *Moody,* 603 U.S. at 726-33).

[316] *See id.* (discussing *PG&E*, 475 U.S. at 12-14).

[317] *Id.* at 31-32.

[318] *Id.* at 32-33 (arguing that states have other opportunities to make their views known, rendering the requirement unnecessary).

characterize or justify Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process—do not obviate this alleged First Amendment violation.[319] They also state that it is "inconsequential that the Commission knows and understands that the [Relevant State Entities'] proposal is not the public utility transmission provider's proposal."[320] Indicated PJM TOs assert specifically that the state-generated information at issue is not relevant to the transmission provider's rate proposal, but rather the compliance filing requirement mandates that transmission providers submit information that "undermines the public utility transmission provider's own advocacy."[321]

### ii. Commission Determination

97. We disagree with the arguments raised on rehearing by Indicated PJM TOs that the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their Order No. 1920 regional transmission planning and cost allocation compliance filings violates the First Amendment.[322] We agree as a general matter that

[319] *See id.* at 33.

[320] *Id.* at 33-34 (citing *Moody*, 603 U.S. at 739-40; *Turner Broad. Sys., Inc. v. FCC*, 512 U.S. 622, 655 (1994)).

[321] *Id.* at 34.

[322] *See id.* at 29-34; *cf.* SPP TOs Rehearing Request at 13-14.

transmission providers have First Amendment rights.[323] However, Order No. 1920-A does not implicate those rights. Order No. 1920-A imposes no actual burden or limitation on transmission providers' speech, but instead requires nothing more than the attachment of one or more files, containing the information provided by Relevant State Entities, to transmission providers' compliance proposals under FPA section 206.

98. As explained, given states' unique role in Long-Term Regional Transmission Planning and the heightened importance of state-developed cost allocation methods and State Agreement Processes, the Commission will consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate.[324] The requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings assists the Commission in monitoring compliance with the requirements related to the Engagement Period, allows the Commission to efficiently consider the views of both Relevant State Entities and transmission providers, and helps ensure that the Commission has a sufficient record on compliance to set a just and

[323] *PG&E*, 475 U.S. at 8.

[324] Order No. 1920-A, 189 FERC ¶ 61,126 at P 659; *supra* P 29.

reasonable replacement rate.[325] Correctly viewed in this light, the compliance requirements of Order No. 1920-A do not compel speech in violation of the First Amendment. Indeed, a myriad of Commission orders have similarly directed public utilities, following a finding that an existing rate is unjust, unreasonable, and unduly discriminatory, to submit information they otherwise would not submit that is necessary for the Commission to determine whether they have met the relevant orders' requirements.[326] Considering the critical importance of Relevant State Entities' views as to how the costs of Long-Term Regional Transmission Facilities will be allocated,[327] the requirement that transmission providers include information concerning those views in their compliance filings is akin to any other "informational requirement[ ] that public

[325] *See supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods, Statutory Filing Rights Under the FPA section.

[326] For example, transmission providers' First Amendment rights were not implicated by Order No. 1000's directive that transmission providers propose on compliance an *ex ante* method(s) for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation and show on compliance (i.e., provide record evidence) that this proposed method(s) is just and reasonable and not unduly discriminatory by, *inter alia*, demonstrating that it satisfies the regional cost allocation principles. Order No. 1000, 136 FERC ¶ 61,051 at PP 558, 603. As in Order No. 1000, Order No. 1920-A requires that transmission providers provide the necessary record evidence—which, given the importance of states' views on cost allocation, necessarily includes those views—for the Commission to act on transmission providers' compliance filings.

[327] Order No. 1920-A, 189 FERC ¶ 61,126 at P 649.

utilities must follow to support their filings"[328] and, therefore, does not implicate any First Amendment concerns.[329]

99. Further, we disagree with Indicated PJM TOs' contention that "the Commission is not requiring the transmission provider to file state-generated information that is relevant to the Commission's decision on the *transmission provider's rate proposal*."[330] Given the importance of Relevant State Entities' views as to how the costs of Long-Term Regional Transmission Facilities will be allocated, we find that those views—and any

[328] Indicated PJM TOs Rehearing Request at 29. *See also* Order No. 1920-A, 189 FERC ¶ 61,126 at P 657 ("[W]e direct these facilitation and informational requirements on compliance pursuant to the Commission's authority under FPA section 206."); *supra* The Statutory Text and Structure, and Applicable Precedent, Support the Commission's Order No. 1920-A Approach section.

[329] *Full Value Advisors, LLC v. SEC*, 633 F.3d 1101, 1108-09 (D.C. Cir. 2011) (holding that required disclosures of information related to the securities over which institutional managers exercise control "are indistinguishable from other underlying and oft unnoticed forms of disclosure the Government requires for its 'essential operations.'" (quoting *W. Va. State Bd. of Educ. v. Barnette*, 319 U.S. 624, 645 (1943) (Murphy, J., concurring)); *United States v. Sindel*, 53 F.3d 874, 878 (8th Cir. 1995) (holding that disclosures required by the Internal Revenue Service did not implicate the First Amendment); *Scahill v. District of Columbia*, 909 F.3d 1177, 1185 (D.C. Cir. 2018); *see also Ohralik v. Ohio State Bar Ass'n*, 436 U.S. 447, 456 (1978) ("Numerous examples could be cited of communications that are regulated without offending the First Amendment, such as the exchange of information about securities, corporate proxy statements, the exchange of price and production information among competitors, and employers' threats of retaliation for the labor activities of employees." (citations omitted)).

[330] Indicated PJM TOs Rehearing Request at 34 (emphasis in original). *Cf.* Order No. 1920-A, 189 FERC ¶ 61,126 at P 659 ("[T]he Commission will consider the entire record – including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal – when setting the replacement rate.").

agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process—are relevant to the Commission's decision on the transmission provider's rate proposal.[331] Moreover, even if this material were not relevant to the assessment of transmission providers' proposals, this would not alter our conclusion that Order No. 1920-A's requirements do not impinge on transmission providers' First Amendment rights, as discussed below.[332]

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[331] *See* Order No. 1920-A, 189 FERC ¶ 61,126 at P 657 ("We find that these additional requirements will allow the Commission to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period." (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1357)).

[332] We further note that the Commission regularly requires public utilities to submit information relevant to other entities' proposals or positions on issues. *See, e.g.*, *pro forma* Large Generator Interconnection Procedures, § 11.3 (Execution and Filing) (requiring, when an interconnection customer determines that negotiations with the transmission provider on the terms of the Large Generator Interconnection Agreement (LGIA) are at an impasse and requests that the transmission provider submit the unexecuted LGIA to the Commission, that the transmission provider "shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree"); *Wholesale Competition in Regions with Organized Elec. Mkts.*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), 125 FERC ¶ 61,071, at P 274 (2008), *order on reh'g*, Order No. 719-A, 74 FR 37776 (Jul. 29, 2009), 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (requiring RTOs/ISOs to submit a compliance filing identifying any significant minority views as to remaining barriers to comparable treatment of jurisdictional demand response resources); *Allegheny Elec. Coop., Inc. v. PJM Interconnection, L.L.C*, 119 FERC ¶ 61,165, at P 14, app., attach. (Data and Document Request to PJM Interconnection, L.L.C) (2007) (directing PJM, in response to a complaint alleging tariff violations by PJM related to actions taken by PJM management with respect to the submission of reports by the PJM Market Monitoring Unit (MMU), to provide "[c]omplete details of any communications . . . with any MMU personnel regarding suggested alterations to the State of the Market Report . . . [and] [a]ny and all documents made in connection with such communication(s)").

100. Turning to Indicated PJM TOs' specific First Amendment claims, as a preliminary matter it is unclear which rights protected by the First Amendment Indicated PJM TOs believe are implicated by Order No. 1920-A. The First Amendment protects against government action abridging both "the freedom of speech" and the right "to petition the government for a redress of grievances."[333] Although the Supreme Court has described these two rights as "cognate rights,"[334] the Court has also explained that courts "should not presume there is always an essential equivalence in the two Clauses or that Speech Clause precedents necessarily and in every case resolve Petition Clause claims."[335] We assume that Indicated PJM TOs' position is that Order No. 1920-A violates both transmission providers' freedom of speech and their right to petition the government,[336] and we therefore address these claims separately.[337]

101. As to the First Amendment right to petition, we disagree with Indicated PJM TOs that the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State

[333] U.S. Const. amend. I.

[334] *Thomas v. Collins*, 323 U.S. 516, 530 (1945).

[335] *Borough of Duryea v. Guarnieri*, 564 U.S 379, 388 (2011).

[336] *See* Indicated PJM TOs Rehearing Request at 29-30 (arguing that Order No. 1920-A "compel[s] speech in violation of the First Amendment" and "violat[es] First Amendment petitioning rights").

[337] *Borough of Duryea*, 564 U.S at 388 (there is not a presumption of "essential equivalence" in the speech and petition clauses negating the need to address them individually).

Agreement Process in their compliance filings violates transmission providers' "First Amendment petitioning rights."[338] The Supreme Court has described the First Amendment right to petition as "allow[ing] citizens to express their ideas, hopes, and concerns to their government," and a petition as "convey[ing] the special concerns of its author to the government and, in its usual form, request[ing] action by the government to address those concerns."[339] Assuming, *arguendo*, that transmission providers' filings made in compliance with the requirements of Order Nos. 1920 and 1920-A—or filings made in compliance with the requirements of any Commission order for that matter[340]—constitute petitions under the First Amendment,[341] we find that the

[338] Indicated PJM TOs Rehearing Request at 30.

[339] *Borough of Duryea*, 564 U.S at 388-89 (citing *Sure-Tan, Inc. v. NLRB*, 467 U.S. 883, 896-97 (1984)).

[340] *S. Co. Svcs.*, 61 FERC at 62,328-29 (1992) ("A compliance filing is not a change initiated by a utility, but rather is a change expressly directed by the Commission . . . which the utility is merely implementing or carrying out."); *id.* at 62,330 ("A public utility submits compliance filings in response to Commission directives. The Commission issues these directives under its authority to fix a rate by order.").

[341] Indicated PJM TOs contend that "a public utility's right to present its rates and charges and proposals that affect such rates and charges with the Commission are protected speech under the First Amendment" based on the general observation that "[m]aking a submission or filing with a governmental body is First Amendment protected petitioning." Indicated PJM TOs Rehearing Request at 29 (citing *Noerr Motor Freight, Inc.*, 365 U.S. at 138; *Trucking Unlimited*, 404 U.S. at 510; *White v. Lee*, 227 F.3d at 1231). However, we find no relevant parallels between, on the one hand, the compliance requirements adopted in Order No. 1920-A and, on the other, the "publicity campaign designed to influence the passage of state laws" in *Noerr Motor Freight, Inc.*, 365 U.S. at 131, the alleged conspiracy "to institute state and federal proceedings to resist and defeat applications . . . to acquire [highway carrier] operating rights or to transfer or

requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings does not infringe on transmission providers' right to petition. Order No. 1920-A does not prevent transmission providers from "express[ing] their ideas" to the Commission or "request[ing] action by the [Commission] to address [their] concerns."[342] Rather, Order No. 1920-A makes clear that "transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments, whether they decide to propose the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process or a different Long-Term Regional Transmission Cost Allocation Method."[343]

102. As to the First Amendment guarantee of freedom of speech, we find that the line of cases Indicated PJM TOs rely on in support of their argument that the compliance requirements of Order No. 1920-A violate transmission providers' right not to speak are inapposite. In both *PG&E* and *Moody*, the Supreme Court reviewed government action regulating the communication of *political* messages to and amongst the *public*.[344] In

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register those rights" in *Trucking Unlimited*, 404 U.S. at 509, or the opposition to a zoning permit in *White v. Lee*.

[342] *See Borough of Duryea*, 564 U.S at 388-89.

[343] Order No. 1920-A, 189 FERC ¶ 61,126 at P 654 n.1651.

[344] *PG&E* concerned an order issued by the California Public Utilities Commission requiring PG&E to include third-party political editorials in its monthly billing statements to its customers. *PG&E*, 475 U.S. at 5-6, 12 (describing the audience of these editorials

contrast with the political discourse at issue in *PG&E* and *Moody*, the Supreme Court has held that under the standard articulated in *Central Hudson Gas & Electric Corp. v. Public Service Commission of New York*,[345] commercial speech—"that is, expression related solely to the economic interests of the speaker and its audience"[346]—is entitled to a "limited measure of protection, commensurate with its subordinate position in the scale of First Amendment values."[347] Further, courts have held that the First Amendment is not violated when agencies require the disclosure of information, not to influence public debate, but instead as a means to fulfilling the agencies' statutory mandates.[348] Given

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as the "public at large"). In *Moody*, the Supreme Court reviewed a Texas law banning censorship on social-media platforms with over 50 million monthly active users, which officials justified on the basis that those platforms "skewed against politically conservative voices." *Moody*, 603 U.S. at 718-19, 721.

[345] 447 U.S. 557 (1980) (*Central Hudson*).

[346] *Id.* at 561; *see also Md. Shall Issue, Inc. v. Anne Arundel Cnty.*, 91 F.4th 238, 248 (4th Cir. 2024) (rejecting the argument that "commercial speech" is limited to speech that "propose[s] a commercial transaction" and describing that argument as "understand[ing] 'commercial' far too narrowly").

[347] *See Bd. of Trs. of State Univ. of N.Y. v. Fox,* 492 U.S. 469, 477 (1989) ("Our jurisprudence has emphasized that 'commercial speech' . . . is subject to 'modes of regulation that might be impermissible in the realm of noncommercial expression.'" (quoting *Ohralik*, 436 U.S. at 456)); *Central Hudson*, 447 U.S. at 563 ("The Constitution therefore accords a lesser protection to commercial speech than to other constitutionally guaranteed expression."); *Bolger v. Youngs Drug Prods. Corp.*, 463 U.S. 60, 64-65 (1983). *See also Rubin v. Coors Brewing Co.*, 514 U.S. 476, 492 (1995) (Stevens, J., concurring) ("The First Amendment generally protects the right not to speak as well as the right to speak. In the commercial context, however, government . . . often requires affirmative disclosures that the speaker might not make voluntarily." (internal citations omitted)).

[348] *See Full Value Advisors, LLC*, 633 F.3d at 1108-09 ("Here the Commission—not the public—is [the regulated entity's] only audience. The

that Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process relate "solely to the economic interests"[349] of those who will be allocated the costs of Long-Term Regional Transmission Facilities, and that disclosure of this information is made to the Commission so that it may ensure compliance with its directives,[350] we find Indicated PJM TOs' reliance on *PG&E* and *Moody* misplaced.[351]

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[Dodd–Frank Wall Street Reform and Consumer Protection] Act is an effort to regulate complex securities markets, inspire confidence in those markets, and protect proprietary information in the process. It is not a veiled attempt to 'suppress unpopular ideas or information or manipulate the public debate through coercion rather than persuasion'" (citing *Turner Broad. Sys., Inc.*, 512 U.S. at 641)); *Sindel*, 53 F.3d at 878 ("There is no right to refrain from speaking when 'essential operations of government may require it for the preservation of an orderly society,—as in the case of compulsion to give evidence in court.' The IRS summons requires [appellant] only to provide the government with information which his clients have given him voluntarily, not to disseminate publicly a message with which he disagrees." (quoting *West Va. State Bd. of Educ. v. Barnette*, 319 U.S. at 645 (Murphy, J., concurring))).

[349] *See Central Hudson*, 447 U.S. at 561; *Md. Shall Issue, Inc.*, 91 F.4th at 248.

[350] *S. Co. Svcs.*, 61 FERC at 62,330. *See also* Order No. 1920, 187 FERC ¶ 61,068 at P 1768 (requiring each transmission provider to submit a compliance filing "as necessary to demonstrate that it meets all of the requirements adopted in [Order No. 1920]").

[351] Indicated PJM TOs cite to, but do not discuss, several additional Supreme Court decisions in stating that "the Commission's desire to receive the views of the [Relevant State Entities] on cost allocation does not justify mandating that the public utility present those views when filing its own proposal." Indicated PJM TOs Rehearing Request at 31 (citing *Turner Broad. Sys., Inc.*, 512 U.S. at 647; *Hurley v. Irish-Am. Gay, Lesbian, & Bisexual Grp. of Bos., Inc.*, 515 U.S. 557, 570 (1995); *Mia. Herald Publ'g Co. v. Tornillo*, 418 U.S. 241, 256-58 (1974)). These cases are distinguishable on the facts from Order No. 1920-A. *Hurley* and *Tornillo*, like *PG&E* and *Moody*, concerned expression in the public sphere on matters beyond those of a purely commercial nature. *See Hurley*, 515 U.S. at 561-62, 570 (discussing whether a public accommodations law prohibiting discrimination on the basis of sexual orientation compelled organizers of

103. Even assuming for the sake of argument that the compliance requirements of Order No. 1920-A implicate transmission providers' freedom of speech under the First Amendment, we disagree with Indicated PJM TOs' contention that any infringement on transmission providers' rights should be judged under strict scrutiny or the form of intermediate scrutiny described by Indicated PJM TOs.[352] In arguing that strict scrutiny should apply because the compliance requirements of Order No. 1920-A are not content-neutral,[353] Indicated PJM TOs ignore that the Supreme Court "has consistently applied intermediate scrutiny to commercial speech restrictions, even those that were content- and speaker-based."[354] We find, assuming Order No. 1920-A's compliance

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Boston's St. Patrick's Day parade to allow a group of openly gay, lesbian, and bisexual descendants of Irish immigrants to march in the parade in violation of organizers' First Amendment rights); *Tornillo*, 418 U.S. at 243 (reviewing a statute "granting a political candidate a right to equal space to reply to criticism and attacks on his record by a newspaper"). Further, the portion of *Turner* cited by Indicated PJM TOs merely discusses why the requirements at issue there were "unrelated to the content of speech" (i.e., content-neutral), and does not explore the appropriate standard of review for regulations concerning a particular category of speech, such as commercial speech. *Turner Broad. Sys., Inc.*, 512 U.S. at 647.

[352] Indicated PJM TOs Rehearing Request at 31.

[353] *Id.* at 31 n.116 ("Here, the requirement to file the [Relevant State Entities'] proposal is applied only when the transmission provider disagrees with the content of the [Relevant State Entities'] proposal." (citing *Reed v. Town of Gilbert*, 576 U.S. 155, 171 (2015); *Turner Broad. Sys., Inc.*, 512 U.S. at 642)).

[354] *Greater Phila. Chamber of Com. v. Philadelphia*, 949 F.3d 116, 138 (3rd Cir. 2020). *See also Sorrell v. IMS Health Inc.*, 564 U.S. 552, 571-72 (2011) (applying *Central Hudson* intermediate scrutiny to a law imposing a "targeted, content-based burden"). The Supreme Court has described a content-based regulation as being "targeted at specific subject matter . . . even if it does not discriminate among viewpoints within that subject matter. *Reed*, 576 U.S. at 169. While content-based regulations of noncommercial speech are typically subject to strict scrutiny, content-based regulations

requirements implicate transmission providers' First Amendment rights at all, the less demanding standard applied to commercial speech set forth in *Central Hudson*, should apply to the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings given that these requirements "relate[ ] solely to [transmission providers'] economic interests."[355] Furthermore, we find that this requirement satisfies *Central Hudson*. Under *Central Hudson*, the Supreme Court undertakes a four-part analysis to determine whether a regulation that infringes on an entity's First Amendment rights is unconstitutional:

> At the outset, we must determine whether the expression is protected by the First Amendment. For commercial speech to come within that provision, it at least must concern lawful activity and not be misleading. Next, we ask whether the asserted governmental interest is substantial. If both inquiries yield positive answers, we must determine whether the regulation directly advances the governmental interest

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of commercial speech are not. *See, e.g.*, *SEC v. AT&T, Inc.*, 626 F. Supp. 3d 703, 743 (S.D.N.Y 2022) ("[D]efendants' suggestion that all content-based regulations must satisfy strict scrutiny overlooks the significant body of decisions involving laws and regulations mandating affirmative disclosures of information . . . . These disclosure provisions are explicitly content based.").

[355] *Central Hudson*, 447 U.S. at 561; *Recht v. Morrisey*, 32 F.4th 398, 409 (4th Cir. 2022) ("To be clear: Commercial speech regulations are analyzed under *Central Hudson.*"); *Stuart v. Camnitz*, 774 F.3d 238, 244 (4th Cir. 2014). *See also Ohralik*, 436 U.S. at 456 ("To require a parity of constitutional protection for commercial and noncommercial speech alike could invite dilution, simply by a leveling process, of the force of the Amendment's guarantee with respect to the latter kind of speech.").

> asserted, and whether it is not more extensive than is necessary to serve that interest.[356]

104. First, the Commission has a substantial interest in monitoring transmission providers' compliance with the requirements concerning the Engagement Period, being able to efficiently consider the views of both Relevant State Entities and transmission providers, and ensuring that when setting the replacement rate on compliance, the record before it includes Relevant State Entities' views concerning how the cost of Long-Term Regional Transmission Facilities will be allocated,[357] and the Commission directly and materially advances that substantial interest by requiring that transmission providers document those views in their compliance filings.[358] Additionally, Order No. 1920-A is not more extensive than is necessary to serve the Commission's substantial interest because it requires only the attachment of one or more files, containing the information provided by Relevant State Entities, to transmission providers' proposal and does not require that transmission providers separately characterize any of this information.[359]

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[356] *Central Hudson*, 447 U.S. at 566. Courts have described the *Central Hudson* analysis as a type of intermediate scrutiny. *See Recht v. Morrisey*, 32 F.4th at 408.

[357] *Central Hudson*, 447 U.S. at 569 ("The State's concern that rates be fair and efficient represents a clear and substantial governmental interest."); Order No. 1920-A, 189 FERC ¶ 61,126 at PP 649, 659.

[358] *Edenfield v. Fane*, 507 U.S. 761, 767 (1993).

[359] Contrary to Indicated PJM TOs' contention, the fact that Relevant State Entities could alternatively submit their agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in comments in response to transmission providers' compliance filings is immaterial under intermediate scrutiny. Indicated PJM TOs Rehearing Request at 32-33. Under intermediate scrutiny, both for content-neutral regulations of noncommercial speech and for commercial speech,

### B. Consultation with Relevant State Entities After the Engagement Period

#### 1. Order Nos. 1920 and 1920-A

105. In Order No. 1920, the Commission declined to require future Engagement Periods but noted that transmission providers may hold future Engagement Periods if they believe that such periods would be beneficial.[360]

106. In Order No. 1920-A, the Commission set aside Order No. 1920, in part, and required that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities: (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process; or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method(s) or process.[361] The Commission found that the consultation requirement will provide a mechanism through which transmission providers and Relevant State Entities can engage with each other regarding possible future FPA

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regulations need not be the least restrictive means of achieving the government's substantial interest. *Recht v. Morrisey*, 32 F.4th at 409; *Bd. of Trs. of State Univ. of N.Y.*, 492 U.S. at 477 ("The ample scope of regulatory authority [with respect to commercial speech] would be illusory if it were subject to a least-restrictive means requirement, which imposes a heavy burden on the State."); *Turner Broad. Sys., Inc.*, 520 U.S. at 217-18 ("Our precedents establish that when evaluating a content-neutral regulation which incidentally burdens speech, we will not invalidate the preferred remedial scheme because some alternative solution is marginally less intrusive on a speaker's First Amendment interests.").

[360] Order No. 1920, 187 FERC ¶ 61,068 at P 1368.

[361] Order No. 1920-A, 189 FERC ¶ 61,126 at P 691.

section 205 filings that seek to change cost allocation methods accepted by the Commission in compliance with Order No. 1920.[362] The Commission further required transmission providers to include in their OATTs a description of how they will consult with Relevant State Entities in these circumstances. Additionally, for a consultation initiated by a transmission provider, the Commission required the transmission provider to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment. For a consultation initiated by Relevant State Entities, if the transmission provider chooses not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation, the Commission also required the transmission provider to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.[363]

107. The Commission found that these requirements will ensure that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of

[362] *Id.* The Commission clarified that this consultation requirement neither requires transmission providers to submit, nor prohibits transmission providers from submitting, FPA section 205 filings to modify cost allocation methods accepted in compliance with Order No. 1920, and transmission providers therefore retain their currently effective FPA section 205 rights. *Id.* P 691 n.1747.

[363] *Id.*

transmission providers' filings made in compliance with Order No. 1920, which has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities.[364] The Commission noted that, while it provided transmission providers with flexibility as to the form and duration of their required consultation with Relevant State Entities, one way transmission providers could satisfy the requirement to consult with Relevant State Entities is by revising their OATTs to include a process under which the transmission provider must present to the Commission, in addition to its own FPA section 205 proposal, an alternative cost allocation method proposed by Relevant State Entities for evaluation by the Commission on equal footing.[365] The Commission noted that transmission providers could also satisfy the requirement to consult with Relevant State Entities by revising their OATTs to include mechanisms similar to those used in SPP[366] and MISO.[367]

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[364] *Id.* P 692 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126).

[365] *Id.* (citing ISO New England Inc., FERC FPA Electric Tariff, ISO New England Inc. Agreements and Contracts, TOA, Transmission Operating Agreement (5.0.0), 3.04(h)(vi)(C); *The Governors of Conn., Me., Mass., N.H., R.I., Vt.*, 112 FERC ¶ 61,049, at P 25 (2005)).

[366] *Id.* (citing SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), 7.2 (Regional State Committee); *Sw. Power Pool, Inc.*, 106 FERC ¶ 61,110, at PP 218-220, *order on reh'g*, 109 FERC ¶ 61,010, at PP 92-94 (2004); *Sw. Power Pool, Inc.*, 108 FERC ¶ 61,003, at P 127 & n.90 (2004), *order on reh'g*, 110 FERC ¶ 61,138, at P 33 (2005)).

[367] *Id.* (citing MISO, FERC Electric Tariff, MISO Rate Schedules, MISO Transmission Owner Agreement, app. K (Filing Rights Pursuant To Section 205 Of The FPA) (3.0.0), II.E.3.a.i-ii; *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,165, at PP 30, 32 (2013)).

### 2. Challenges to Order No. 1920-A

#### a. Statutory Filing Rights Under the FPA

##### i. Rehearing Requests

108. Several rehearing petitioners argue that the consultation requirement unlawfully impinges on transmission providers' FPA section 205 filing rights by conditioning the exercise of those rights on consultation with Relevant State Entities before filing a proposed tariff amendment.[368] They argue that FPA section 205 is intended for the benefit of the public utilities, that this provision provides public utilities with the unilateral and exclusive right to make filings setting their rates (subject to Commission approval), and that the Commission cannot encumber this right by conditioning it on such consultation.[369] In support, some rehearing petitioners cite *Atlantic City I* as reflecting that the Commission cannot abridge the statutory rights afforded to public utilities by Congress.[370] MISO TOs, SPP TOs, and WIRES also rely on a statement in *City of*

[368] *See* MISO TOs Rehearing Request at 5-9, 27-31; Indicated PJM TOs Rehearing Request at 3, 7; SPP TOs Rehearing Request at 2, 7, 10-12; EEI Rehearing Request at 7, 11-12; WIRES Rehearing Request at 5-9.

[369] *See, e.g.*, MISO TOs Rehearing Request at 29-31 (citing *Atlantic City I*, 295 F.3d at 9-10; *Emera Maine*, 854 F.3d at 24; *Vistra Corp. v. FERC*, 80 F.4th 302, 318 (D.C. Cir. 2023); *MISO Transmission Owners v. FERC*, 45 F.4th 248, 253 (D.C. Cir. 2022); EEI Rehearing Request at 13-14 ("In seeking to create such a condition, the Commission seeks to fundamentally and unlawfully alter its role, as well as transmission providers' and public utilities' rights, under section 205."); WIRES Rehearing Request at 7-8.

[370] *See, e.g.*, MISO TOs Rehearing Request at 27-28; EEI Rehearing Request at 13-14; WIRES Rehearing Request at 7-8; SPP TOs Rehearing Request at 11 (also

*Cleveland v. Federal Power Commission* that a public utility "may, without negotiation or consultation with anyone, set the rates it will charge prospective customers, and change them at will, so long as they have not been set aside by the Commission on grounds of inconsistency with the [FPA]."[371]

109. MISO TOs argue that the requirement that transmission providers consult with Relevant State Entities prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process "encumbers the transmission providers' ability to exercise their FPA section 205 rights to amend their tariffs 'at any time.'"[372] SPP TOs similarly argue that the Commission cannot "impos[e] pre-conditions that could delay section 205 filings, potentially for an indefinite time."[373] WIRES argues that this requirement is a pre-condition to transmission providers exercising their filing

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asserting that this approach contravenes *Massachusetts Department of Public Utilities*, 729 F.2d at 888).

[371] 525 F.2d 845, 855 (D.C. Cir. 1976) (*City of Cleveland*) (citing *United Gas Pipe Line Co.*, 350 U.S. at 338-344; *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968)); *see* MISO TOs Rehearing Request at 30-31 (also noting the Commission's passive role under FPA section 205); SPP TOs Rehearing Request at 7; WIRES Rehearing Request at 6, 8.

[372] MISO TOs Rehearing Request at 27-29 (quoting *Atlantic City I*, 295 F.3d at 9) (asserting that this aspect of Order No. 1920-A "provides Relevant State Entities with the ability to delay and exert statutorily inappropriate influence or control over the transmission providers' statutory right to file rate changes").

[373] SPP TOs Rehearing Request at 11 (citing *NRG Power Mktg.*, 862 F.3d at 115; *Western Resources*, 9 F.3d at 1578; *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221 (2010), *order on reh'g*, 137 FERC ¶ 61,074, at P 187 (2011), *vacated in part sub nom. Ill. Com. Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013)).

rights that is not contemplated under the statute which could, "[i]n the extreme, . . . serve as a prohibition to a public utility's ability to file revisions under FPA section 205," in contrast to the intent of the FPA to allow public utilities to act quickly and without obstacles.[374]

110. EEI asserts that the consultation requirement impermissibly changes the Commission's role from passively considering rate proposals to actively infringing upon public utilities' exclusive power under FPA section 205 to initiate rate changes.[375] EEI contends that the structure of the consultation requirement implicitly shows that the Commission recognizes that it cannot reject a tariff filing by a public utility for failing to consult a Relevant State Entity.[376]

111. A number of the rehearing requests also argue that decisions by public utilities to adopt a similar consultation mechanism in certain circumstances, allow greater state participation in regional transmission planning or cost allocation, or otherwise cede their FPA section 205 filing rights to other entities do not support the Commission's decision here because those decisions were voluntary, rather than compelled by the Commission.[377] EEI recommends that the Commission reconsider the consultation

[374] WIRES Rehearing Request at 8-9.

[375] EEI Rehearing Request at 13.

[376] *Id.* at 14.

[377] *See* MISO TOs Rehearing Request at 29; SPP TOs Rehearing Request at 5-6; EEI Rehearing Request at 14-15.

requirement, averring that uncoerced, voluntary agreements, such as when transmission owners in the MISO region voluntarily ceded certain rights to the Organization of MISO States in 2013, offer a lawful and more appropriate means of ensuring engagement between transmission providers and Relevant State Entities.[378]

112. MISO TOs, Indicated PJM TOs, and SPP TOs contend that Order No. 1920-A is also inconsistent with the FPA in requiring, in certain circumstances, that transmission providers publicly document the results of their consultations with Relevant State Entities on transmission providers' OASIS or other public website.[379] In particular, SPP TOs assert that the Commission may not "require a public utility to justify a decision *not* to make a section 205 filing when the filing decision is wholly voluntary under the FPA."[380] Indicated PJM TOs argue, citing *Atlantic City I*, that "inherent in a public utility's right to file to change its own rates under section 205 is its right to *not* change its own just and reasonable rates" and that "nothing in section 205 requires a utility to explain why it is not changing a just and reasonable rate."[381]

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[378] EEI Rehearing Request at 14-15 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,165 at P 30).

[379] *See* MISO TOs Rehearing Request at 5 ("These changes reframe the roles of the entities involved, blurring the FPA's division of authority."); Indicated PJM TOs Rehearing Request at 7, 15-17; SPP TOs Rehearing Request at 2, 7, 10-11.

[380] SPP TOs Rehearing Request at 11.

[381] Indicated PJM TOs Rehearing Request at 16; *id.* at 16-17 (arguing that the statutory vehicle for Relevant State Entities to attempt to change a Commission-approved cost allocation method is a complaint pursuant to FPA section 206).

### ii. Commission Determination

113. We disagree with the arguments that Order No. 1920-A's cost allocation consultation requirement is unlawful because it infringes on or abridges transmission providers' FPA section 205 filing rights. The consultation requirement does not regulate transmission providers' filing rights under FPA section 205, but rather addresses the practices through which cost allocation methods for Long-Term Regional Transmission Facilities are developed, which is integrally tied to the likelihood of the construction of those facilities and their associated costs.[382]

114. In Order No. 1000, the Commission required—and the D.C. Circuit upheld—that transmission providers' transmission planning processes "have a method for allocating *ex ante* among beneficiaries the costs of new transmission facilities in the regional transmission plan, and the method must satisfy six regional cost allocation principles."[383] In doing so, the Commission regulated not only the substantive content of such cost allocation methods (i.e., consistency with the six regional cost allocation principles), but also the very practice of developing cost allocation methods by "[r]eforming the practice[ ] of failing to engage in . . . *ex ante* cost allocation."[384] Order No. 1920-A's

[382] *South Carolina*, 762 F.3d at 48; *see id.* at 82-83 (discussing how "the lack of methods that ascertain the beneficiaries of new and improved transmission facilities and allocate costs to entities that benefit" creates risks to transmission providers and results in misaligned incentives).

[383] *Id.* at 48.

[384] *Id.* at 57 (holding that this reform was within the Commission's jurisdiction to regulate); *see also id.* at 84-87.

consultation requirement, similarly, aims to ensure the development and application of cost allocation methods that will themselves facilitate the timely, efficient development of Long-Term Regional Transmission Facilities, through states' critical role in that process.

115. In Order No. 1920-A, the Commission determined—and we here sustain—that requiring transmission providers to consult with Relevant State Entities will provide an opportunity for state input, which "has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities."[385] As the Commission explained in the NOPR, Long-Term Regional Transmission Planning "may entail a more complex set of considerations compared to existing regional transmission planning requirements, which, in turn, may increase the importance of ensuring that the cost allocations method for projects identified and developed through these processes are perceived as fair."[386] "As

[385] Order No. 1920-A, 189 FERC ¶ 61,126 at P 692 ("We find that these requirements will ensure that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920.").

[386] NOPR, 179 FERC ¶ 61,028 at P 54 (proposing to "address these concerns in part through greater state involvement, particularly in the development of cost allocation methods"); *see id.* P 244; *id.* PP 297-300 (discussing the challenges associated with developing cost allocation methods perceived as fair, especially in multi-state transmission planning regions, and how this may undermine the development of more efficient or cost-effective regional transmission facilities; discussing the critical role of states in such processes); *id.* P 301 ("We believe that providing an opportunity for state involvement in regional transmission planning cost allocation processes is becoming more important as states take a more active role in shaping the resource mix and demand, which, in turn, means that those state actions are increasingly affecting the long-term

such, . . . state entities charged with siting transmission facilities within their state may, at least in certain circumstances, take a more skeptical approach to evaluating applications to site Long-Term Regional Transmission Facilities."[387] To address this problem, the Commission proposed that providing opportunities for state involvement in establishing a cost allocation method "would help to address any such concerns on the part of state regulators, increasing the likelihood that Long-Term Regional Transmission Facilities are actually developed, and without delay."[388]

116. Order No. 1920 sustained these preliminary findings from the NOPR, which provide the foundation for the expanded opportunities for state participation in cost allocation adopted in that order and in Order No. 1920-A.[389] The Commission in Order

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transmission needs for which we are proposing to require public utility transmission providers to plan in this NOPR.").

[387] *Id.* P 317; *see also id.* P 314 (discussing how additional state involvement in cost allocation may "decrease the controversy over development of such facilities," and thereby "reduce instances in which a Long-Term Regional Transmission Facility is selected, has an established *ex ante* cost allocation method that applies to it, but nevertheless fails to be developed because it cannot receive a necessary state regulatory approval. After all, states retain siting authority over transmission facilities and will review whether Long-Term Regional Transmission Facilities are consistent with the public interest and state siting regulations."); *cf. id.* P 321 ("Moreover, state siting proceedings may proceed more efficiently if states have better information about the costs and benefits of such regional transmission facilities.").

[388] *Id.* P 317.

[389] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 124 ("As the Commission discussed in the NOPR and we continue to find in this final rule, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings."); *id.* P 126 (concluding that ensuring a dedicated process through which states have an opportunity to participate in the development of regional cost allocation "is particularly relevant to

No. 1920-A recognized that such concerns over inadequate state participation—and the Commission's findings as to how increased state involvement in cost allocation can help ensure that the benefits of Long-Term Regional Transmission Planning are realized—will also arise in the future, as transmission providers consider whether changes are warranted to the cost allocation process.[390] Likewise, the same dynamic may occur where Relevant State Entities have identified an alternative approach to the existing cost allocation mechanism; consulting with the Relevant State Entities regarding alternative approaches may increase Relevant State Entities' confidence in Long-Term Regional Transmission

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Long-Term Regional Transmission Planning, given: (1) the lengthy planning horizon . . . ; (2) the resultant increased uncertainty for Long-Term Regional Transmission Facilities; and (3) accordingly, the increased importance for state engagement regarding cost allocation to increase the likelihood such facilities obtain needed siting approvals from the states and are thus timely and cost-effectively developed"); *id.* PP 1293, 1295, 1362, 1404, 1411; Order No. 1920-A, 189 FERC ¶ 61,126 at P 659 ("[G]iven the inherent uncertainty involved in planning to meet Long-Term Transmission Needs, state-developed cost allocation methods and State Agreement Process take on heightened importance."); *id.* PP 10, 59; 632, 671-673, 677-678.

[390] *See* Order No. 1920-A, 189 FERC ¶ 61,126 at P 692 ("We find that these requirements will ensure that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920, which has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities."); *see also id.* P 688 (summarizing NESCOE's argument that "a transmission provider could undo the efforts of Relevant State Entities in agreeing to a Long-Term Regional Transmission Cost Allocation Method during the initial Engagement Period by filing a new Long-Term Regional Transmission Cost Allocation Method without consulting with Relevant State Entities"); *id.* P 691 ("We are persuaded by NARUC's and NESCOE's arguments raised on rehearing.").

Planning processes, thereby minimizing delays, disputes, and costs associated with those processes.

117. The Commission in Order No. 1920-A therefore addressed transmission providers' processes for developing cost allocation methods for Long-Term Regional Transmission Facilities by requiring that transmission providers engage in consultation with Relevant State Entities on cost allocation to receive input from these key stakeholders.[391] Specifically, it required the adoption of the consultation mechanisms discussed above, and required "transmission providers to include in their OATTs a description of how they will consult with Relevant State Entities in these circumstances."[392] These consultation practices occur prior to any FPA section 205 filing that transmission providers might make addressing cost allocation and are directed toward transmission providers' communications with Relevant State Entities regarding cost allocation, rather than any such FPA section 205 filing.[393]

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[391] Order No. 1920-A also provided examples of how transmission providers could satisfy these consultation requirements, including revising their OATTs to adopt mechanisms similar to those used in SPP and MISO, *id.* P 692, but it did not rely on the voluntary decision of RTOs/ISOs to adopt such mechanisms as support for establishing these requirements. Thus, arguments on rehearing that such voluntary decisions are distinguishable from a Commission-imposed consultation requirement, *see* MISO TOs Rehearing Request at 29; SPP TOs Rehearing Request at 5-6; EEI Rehearing Request at 14-15, are beside the point.

[392] Order No. 1920-A, 189 FERC ¶ 61,126 at P 691.

[393] Indeed, there may not be any FPA section 205 filing associated with any such consultation, as the transmission provider has full discretion on whether or not to proceed with any FPA section 205 filing.

118. We agree with rehearing petitioners that FPA section 205 expressly grants rights to transmission providers. But contrary to the arguments raised on rehearing,[394] regulation of these consultation practices does not infringe on those rights.[395] Transmission providers retain their full and exclusive discretion as to whether to file—or not file—proposed changes to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process under FPA section 205. Transmission providers likewise retain their full and exclusive discretion to determine the content of any such proposal, notwithstanding that transmission providers are required to engage in this consultation process. Transmission providers also control the timing of when they choose to make any such filing, including, to reiterate, *whether to make such a filing at all*.[396] Under this framework, the Commission demonstrably retains its passive and reactive role of reviewing the transmission providers' FPA section 205 filings.[397] As a result, FPA section 205 continues to function to the benefit of the transmission providers

[394] *See supra* P 108.

[395] Order No. 1920-A, 189 FERC ¶ 61,126 at P 691 n.1747 ("We clarify that this consultation requirement neither requires transmission providers to submit, nor prohibits transmission providers from submitting, FPA section 205 filings to modify cost allocation methods accepted in compliance with Order No. 1920, and transmission providers therefore retain their currently effective FPA section 205 rights.").

[396] The Commission also afforded "transmission providers flexibility as to the form and duration of their required consultation with Relevant State Entities." *Id.* P 692.

[397] *Emera Maine*, 854 F.3d at 24.

in allowing them, subject to Commission review and approval, to propose to set and change their own rates.[398]

119. Thus, the precedent relied on by rehearing petitioners challenging these requirements is inapposite. As discussed in greater detail above, the court in *Atlantic City I*[399] was not addressing a Commission regulation akin to the regulation of transmission providers' consultation practices relating to cost allocation for Long-Term Regional Transmission Facilities.[400] Rather, the court there overturned a Commission order requiring that public utilities clearly cede to an ISO their FPA section 205 rights, such that only the ISO could propose changes in rate design. Here, by contrast, transmission providers retain the full scope of their FPA section 205 filing rights. For similar reasons, this consultation requirement does not contravene *Massachusetts Department of Public Utilities*[401] because transmission providers retain their full authority to file only the FPA section 205 proposals of their own choosing, as well as the right to file nothing at all.[402]

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[398] *See, e.g.*, *id.* (contrasting FPA sections 205 and 206, noting that FPA section 205 is intended for the benefit of the utility, allowing it to propose to change its own rates, subject to the Commission's passive and reactive oversight); *Vistra Corp.*, 80 F.4th at 318; *MISO Transmission Owners*, 45 F.4th at 253.

[399] 295 F.3d at 9-11.

[400] *See supra* P 55 (discussing the facts and holding of *Atlantic City I*).

[401] 729 F.2d at 886-87.

[402] *See supra* P 57 (discussing the facts and holding of *Massachusetts Department of Public Utilities*). For similar reasons, we are not persuaded by Indicated PJM TOs' suggestion of a tension between this consultation requirement and the availability of a

120. We are also not persuaded by challenges to this consultation requirement relying on *City of Cleveland*.[403] In that case, the court considered "whether the Federal Power Commission erred in adopting a rate structure specified in a schedule filed by a public electric utility without resolving its municipal customer's contention that the schedule contravenes a preexisting agreement between the parties."[404] The court held that where a public utility has actually agreed to particular rates, by contract, the Commission cannot overlook that agreement and approve different rates.[405] While the court in that case stated that a utility "may, without negotiation or consultation with anyone, set the rates it will charge prospective customers, and change them at will, so long as they have not been set aside by the Commission on grounds of inconsistency with the [FPA],"[406] the court was

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complaint under FPA section 206 as a mechanism to compel a change to a transmission provider's cost allocation method. *See* Indicated PJM TOs Rehearing Request at 16-17. The consultation requirement does not allow Relevant State Entities to compel a transmission provider to change or not change its cost allocation method.

[403] *See* MISO TOs Rehearing Request at 30-31; SPP TOs Rehearing Request at 7; WIRES Rehearing Request at 6, 8.

[404] *See City of Cleveland*, 525 F.2d at 846, 853-54.

[405] *See id.* at 855 (explaining that the petitioner's "thesis is that . . . it had reached agreement with CEI as to the rates to be charged for the proposed load transfer service, and that a racheting of contract demand was not a part of the bargain" such that a "rachet clause" included in the public utility's proposed rate schedule had been impermissibly included); *id.* at 855-56 ("[A] utility is no more at liberty to alter an agreed rate as yet unfiled than it is to depart from one that has been filed.").

[406] *Id.* at 855; *see also United Gas Pipe Line Co.*, 350 U.S. at 343 ("The obvious implication is that, except as specifically limited by the Act, the rate-making powers of natural gas companies were to be no different from those they would possess in the

not called upon to address the Commission's authority, under FPA section 206, to regulate transmission providers' practices for developing cost allocation methods.[407] Moreover, that decision substantially pre-dates the Supreme Court and D.C. Circuit's precedent affirming the Commission's authority over the practices of public utilities that directly affect the areas subject to the Commission's jurisdiction.[408] Regardless, under Order No. 1920-A, transmission providers are still entitled, subject to Commission review and approval, "without negotiation or consultation with anyone, [to] *set* the rates [they] will charge prospective customers, and *change* them at will,"[409] including as to cost allocation. Despite Order No. 1920-A's regulation of their pre-filing practices, transmission providers' filing rights as set forth by FPA section 205[410] remain wholly intact and unchanged; any FPA section 205 filing that transmission providers make seeking to set or change their rates does not need to reflect a compromise proposal resulting from negotiation or consultation.

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absence of the Act: to establish ex parte, and change at will, the rates offered to prospective customers . . . .").

[407] *See City of Cleveland*, 525 F.2d at 851-57.

[408] *See EPSA*, 577 U.S. at 288; *South Carolina*, 762 F.3d at 48; *cf. CAISO*, 372 F.3d at 403 (overturning Commission order, finding that it did not meet the "directly affects" test).

[409] *City of Cleveland*, 525 F.2d at 855 (emphasis added).

[410] *See* 16 U.S.C. 824d(c) (providing that "every public utility shall file with the Commission . . . schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges").

121. MISO TOs, SPP TOs, and WIRES assert that the requirement that transmission providers consult with Relevant State Entities prior to an FPA section 205 filing unlawfully limits their ability to propose to change their rates at any time.[411] We disagree. Order No. 1920-A's regulation of transmission provider practices in this respect may result in practical considerations affecting the timing of transmission providers' FPA section 205 filings, which transmission providers must plan for in order to file their proposal at their preferred time, but it does not amount to a curtailment of transmission providers' filing rights. Indeed, the same challenge could be leveled at essentially *any* Commission order that imposes a requirement on a public utility that may affect the contents of a FPA section 205 filing, because meeting this requirement could impose a practical constraint on the timing of that filing.[412] We note that transmission providers must follow any applicable stakeholder processes to that effect under their currently effective governing documents, and we view those to be functionally similar to the consultation requirement.[413]

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[411] *See supra* P 109.

[412] For instance, where the Commission imposes a requirement on a public utility to consider a certain issue (e.g., a category of factors affecting Long-Term Transmission Needs) in support of ensuring just and reasonable rates, doing so could delay the utility's ability to make an FPA section 205 filing as compared to a situation without that requirement.

[413] *See, e.g.*, PJM Interconnection, L.L.C., Intra-PJM Tariffs, OA, § 18.6(a) (requiring the support of PJM stakeholders for certain FPA section 205 filings to amend PJM's Operating Agreement).

122. None of the precedent cited by MISO TOs, SPP TOs, or WIRES holds to the contrary. While *Atlantic City I* states that under FPA section 205(d) "a public utility may file changes to rates, charges, classification, or service at any time upon 60 days notice,"[414] it does not suggest that a Commission regulation that might, as a practical matter, affect the timing of such filings is unlawful as an intrusion on public utilities' filing rights.[415] Neither do the cases on which SPP TOs rely,[416] which addressed Commission attempts to modify a FPA section 205 filing made by a public utility[417] or explained that, where a filing is made under FPA section 205, the Commission has "a statutory obligation to process the filing in a timely manner."[418]

123. Challenges to Order No. 1920-A's requirements that transmission providers publicly document the results of their consultation with Relevant State Entities[419] do not change our analysis. Here, too, these documentation requirements do not impinge on or

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[414] 295 F.3d at 9; *see* MISO TOs Rehearing Request at 28.

[415] *See* 295 F.3d at 9-11; *see supra* P 55 (discussing the holding of *Atlantic City I*).

[416] *See* SPP TOs Rehearing Request at 11 (citing *NRG Power Mktg*., 862 F.3d at 115; *City of Winnfield*, 774 F.2d at 876; *Western Resources*, 9 F.3d at 1578; *Midwest Indep. Transmission Sys. Operator, Inc*., 137 FERC ¶ 61,074 at P 187).

[417] *See NRG Power Mktg.*, 862 F.3d at 115; *City of Winnfield*, 774 F.2d at 876; *Western Resources*, 9 F.3d at 1578. That these cases discuss notice requirements under FPA section 205 does not support SPP TOs' suggestion that a Commission regulation is invalid as abridging FPA section 205 filing rights if it may, as a practical matter, require greater planning on a public utilities' part to make their filing at a desired time.

[418] *Midwest Indep. Transmission Sys. Operator, Inc*., 137 FERC ¶ 61,074 at P 187.

[419] *See* MISO TOs Rehearing Request at 5; Indicated PJM TOs Rehearing Request at 7, 15-17; SPP TOs Rehearing Request at 2, 7, 10-11.

alter transmission providers' FPA section 205 filing rights, as transmission providers retain their full, exclusive, and unilateral right to file, or not file,[420] FPA section 205 proposals of their own choosing. This aspect of Order No. 1920-A regulates only transmission providers' practices around publicly documenting their consultation with Relevant State Entities, pursuant to the Commission's authority under FPA section 206. The Commission has often introduced documentation requirements aimed at increasing transparency.[421] Nothing in FPA section 205 precludes the Commission from exercising

[420] *See* Indicated PJM TOs Rehearing Request at 16 (arguing that inherent in a public utility's right to change its own rates under FPA section 205 is the right not to seek to change its rates under that provision); SPP TOs Rehearing Request at 11 (arguing that the filing decision is wholly voluntary under FPA section 205).

[421] *See, e.g.*, Order No. 1920, 187 FERC ¶ 61,068 at P 1753 (requiring transmission providers to publicly document certain information, including Long-Term Transmission Needs discussed in interregional transmission coordination meetings); *id.* PP 1625-1630 (establishing documentation and transparency requirements for local transmission planning processes); Order No. 2023, 184 FERC ¶ 61,054 at PP 135-137 (requiring transmission providers to publicly post available generator interconnection information); Order No. 1000, 136 FERC ¶ 61,051 at P 458 (directing transmission providers "to maintain a website or e-mail list for the communication of information related to interregional transmission coordination procedures" to stakeholders); *id.* PP 668-669 (requiring that "cost allocation methods and their corresponding data requirements for determining benefits and beneficiaries [of regional and interregional transmission facilities] must be open and transparent" in order to "ensure[] that such methods are just and reasonable and not unduly discriminatory or preferential"); *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 163 FERC ¶ 61,043, at PP 305, 307 (requiring transmission providers to post interconnection study metrics, in order to "increase the transparency of interconnection study completion timeframes"), *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137 (2018), *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019); *Uplift Cost Allocation & Transparency in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 844, 163 FERC ¶ 61,041, at PP 27, 30-34 (2018) (finding that certain RTO/ISO reporting practices were insufficiently transparent, resulting in unjust and unreasonable rates, and establishing four public reporting requirements).

that FPA section 206 authority to require documentation of these discussions, including in scenarios where the transmission provider elects not to file an FPA section 205 proposal to change its approach to cost allocation.

124. Moreover, the Commission has authority under the FPA to require the disclosure of information as necessary or appropriate to assist the Commission in the administration of its duties under the FPA, in the "manner or form" as the Commission may prescribe and providing "specific answers to all questions upon which the Commission may need information."[422] Order No. 1920-A's requirements that transmission providers publicly document the results of their consultation with Relevant State Entities fall comfortably within this broad authority.[423]

### b. Compliance with the APA

#### i. Rehearing Requests

125. MISO TOs, SPP TOs, and WIRES assert that Order No. 1920-A's consultation requirement is inconsistent with the objectives of Order No. 1920 and insufficiently

[422] 16 U.S.C. 825c(a) ("[E]very public utility shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this chapter"); *see also id.* 825f(a), 825h; *INGAA,* 285 F.3d at 39; *PJM Interconnection* ¶ 61,224, at P 26 (2015) ("Court and Commission precedent recognize that the Commission retains the ability to require informational filings without exceeding its authority under section 205. The Commission's authority to prescribe informational filings and require informational reports, moreover, is statutory."); *PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,037, at P 12 (2008); *supra* note 421 (public documentation requirements issued pursuant to FPA section 206).

[423] For instance, these requirements will help ensure that consultations with Relevant State Entities are occurring consistent with transmission providers' tariffs.

supported and is therefore arbitrary and capricious under the APA.[424] MISO TOs argue that the requirement contravenes the stated purpose of Order No. 1920 of promoting efficiency and cost-effectiveness of transmission solutions stating that "when the Commission places roadblocks, such as additional consultations and detailed explanations of decisions, in the way of reaching appropriate [c]ost [a]llocation [m]ethods, it belies the purpose of the reforms, does not demonstrate a clear path of reasoning, and is, thus, arbitrary and capricious."[425] SPP TOs broadly challenge Order No. 1920-A's consultation requirement as insufficiently supported by the Commission's explanation that states have a unique role and voice in regional transmission planning, given that states have other avenues to be heard and transmission providers have every incentive to consult voluntarily with Relevant State Entities.[426] WIRES argues that "[b]ecause the record demonstrates that there are other less intrusive means by which

[424] MISO TOs Rehearing Request at 32-33 (citing 5 U.S.C. 706; *Hoopa Valley Tribe v. FERC*, 913 F.3d 1099, 1102 (D.C. Cir. 2019)); SPP TOs Rehearing Request at 28 (citing *State Farm*, 463 U.S. at 43); WIRES Rehearing Request at 15 (citing 5 U.S.C. 706(2)(A); *Am. Gas Ass'n v. FERC*, 593 F.3d 14, 19 (D.C. Cir. 2010); *Rio Grande Pipeline Co. v. FERC*, 178 F.3d 533, 541 (D.C. Cir. 1999)).

[425] MISO TOs Rehearing Request at 32-33; *see also id.* at 27.

[426] SPP TOs Rehearing Request at 28-29 (arguing that there is no need to "create preferential filing privileges" not contemplated by the FPA and "that statutory limits exist and may frustrate some parties cannot be a reasoned basis for evading those limits"); *see also id.* at 11-12 (arguing that the Commission's explanation for the consultation requirements cannot support infringing on transmission providers' FPA section 205 filing rights, and that "public utilities will continue to have every incentive to *voluntarily* consult with Relevant State Entities and to consider their input before making section 205 filings").

states can meaningfully participate in the development of Long-Term Regional [Transmission] Cost Allocation [M]ethods and State Agreement Processes, the Commission's revisions are arbitrary and capricious."[427]

### ii. Commission Determination

126. We disagree with the arguments raised on rehearing that the Commission failed to comply with the APA in adopting the requirement that transmission providers consult with Relevant State Entities prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.[428] First, MISO TOs mischaracterize the consultation requirement in calling it a "roadblock[ ] . . . in the way of reaching appropriate [c]ost [a]llocation [m]ethods,"[429] as Order No. 1920-A provides transmission providers flexibility as to both the form and duration of the required consultation.[430] Moreover, Order No. 1920-A does not require that transmission

[427] WIRES Rehearing Request at 16-17 (asserting that the same set of facts relied on in Order No. 1920 were used to justify the requirements of Order No. 1920-A, such that "there seems little connection between what are essentially the same facts and the choices made."). WIRES here challenges both the consultation requirements and the compliance filing requirements adopted in Order No. 1920-A, discussed above, *see supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods section, as arbitrary and capricious for the same reasons.

[428] *See* MISO TOs Rehearing Request at 32-33; SPP TOs Rehearing Request at 28; WIRES Rehearing Request at 15.

[429] MISO TOs Rehearing Request at 33.

[430] Order No. 1920-A, 189 FERC ¶ 61,126 at P 692.

providers post any detail beyond the results of any consultation,[431] and for consultations initiated by Relevant State Entities, Order No. 1920-A requires only an explanation for why the transmission provider has chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation.[432] Contrary to MISO TOs' contention that the consultation requirement contravenes the purpose of Order No. 1920, we find that the consultation requirement directly furthers the essential purpose of Long-Term Regional Transmission Planning to develop more efficient or cost-effective regional transmission facilities.[433] The consultation requirement, in ensuring that states have the opportunity to be involved in development of cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920, has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities.[434] Therefore, on balance, we find that the consultation requirement adopted in

[431] *See* MISO TOs Rehearing Request at 33 (asserting that that this requirement obligates transmission providers to provide "detailed explanations of decisions").

[432] Order No. 1920-A, 189 FERC ¶ 61,126 at P 691.

[433] Order No. 1920, 187 FERC ¶ 61,068 at P 125.

[434] Order No. 1920-A, 189 FERC ¶ 61,126 at P 692.

Order No. 1920-A is an appropriate, tailored means of furthering Order No. 1920's essential purpose.

127. We also disagree with SPP TOs' and WIRES' arguments that the Commission's adoption of the consultation requirement is arbitrary or capricious because Relevant State Entities have other means of participating in the development of Long-Term Regional Transmission Cost Allocation Methods and/or State Agreement Process, or because transmission providers would otherwise be incented to consult with Relevant State Entities and consider their input before making FPA section 205 filings.[435] In Order No. 1920-A, the Commission found that the consultation requirement will ensure that states have the opportunity to be involved in developing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920.[436] Transmission providers may already have an incentive to provide states with an opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920—given such involvement has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission

[435] *See* SPP TOs Rehearing Request at 28-29; WIRES Rehearing Request at 16-17.

[436] Order No. 1920-A, 189 FERC ¶ 61,126 at P 692.

Facilities.[437] However, the consultation requirement adopted in Order No. 1920-A *ensures* that Relevant State Entities have such an opportunity.

### c. First Amendment

#### i. Rehearing Requests

128. Indicated PJM TOs argue that the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation violates the First Amendment to the United States Constitution.[438] Indicated PJM TOs contend that the First Amendment protects transmission providers' right to speak as well as their right not to speak, and that this requirement constitutes governmentally compelled speech that the Commission cannot require.[439]

#### ii. Commission Determination

129. Above, we address Indicated PJM TOs' argument that transmission providers' First Amendment rights are violated by Order No. 1920-A's requirement that transmission providers include in the transmittal or as an attachment to their Order No. 1920 regional transmission planning and cost allocation compliance filing the

[437] *Id.* P 692 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126).

[438] Indicated PJM TOs Rehearing Request at 29.

[439] *Id.* at 29-30, 33-34 (citing *Wooley*, 430 U.S. at 714; *United Foods, Inc.*, 533 U.S. at 409-10; *PG&E*, 475 U.S. at 10-19; *Central Hudson*, 447 U.S. 557).

Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed to by Relevant State Entities during the Engagement Period.[440] For similar reasons, we find that the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation does not implicate transmission providers' rights under the First Amendment. As discussed above,[441] the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation is a regulation of the practices surrounding cost allocation to ensure the development of cost allocation methods that will facilitate the timely, efficient development of Long-Term Regional Transmission Facilities, given the critical role of states in that process. This requirement is not a "veiled attempt to . . . 'manipulate the public debate through coercion'"[442] but rather an integral component in Order No. 1920's

[440] *See supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods section.

[441] Consultation with Relevant State Entities After the Engagement Period, Statutory Filing Rights Under the FPA section.

[442] *Full Value Advisors, LLC*, 633 F.3d at 1108-09 (rejecting a First Amendment challenge to a statute "indistinguishable from other underlying and oft unnoticed forms of disclosure the Government requires for its 'essential operations'" (first quoting *Turner Broad. Sys., Inc.*, 512 U.S. at 641; then quoting *W. Va. State Bd. of Educ. v. Barnette,* 319

reforms facilitating the timely, efficient development of Long-Term Regional Transmission Facilities, and thus ensuring just and reasonable Commission-jurisdictional rates. We therefore find no difference for the purposes of the First Amendment between this requirement and Order No. 1000's reform, necessary to ensure just and reasonable Commission-jurisdictional rates, of the "practices of failing to engage in . . . *ex ante* cost allocation for development of new regional transmission facilities."[443]

130. As with Indicated PJM TOs' First Amendment arguments with respect to the requirement that transmission providers include Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process in their compliance filings, we find that Indicated PJM TOs' reliance on cases concerning compelled expression of political and ideological messages such as *Wooley* and *PG&E* is misplaced. The Supreme Court has consistently held that "expression related solely to the economic interests of the speaker and its audience"[444] is entitled to only a "limited measure of protection, commensurate with its subordinate position in the scale of First Amendment values."[445] The requirement that transmission providers

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U.S. at 645)). *See also Sindel*, 53 F.3d at 878; *Scahill v. District of Columbia*, 909 F.3d at 1185.

[443] *South Carolina*, 762 F.3d at 57 (describing this Order No. 1000 reform as "involv[ing] a core reason underlying Congress' instruction in [FPA] Section 206").

[444] *Central Hudson*, 447 U.S. at 561; *see also Md. Shall Issue, Inc.*, 91 F.4th at 248.

[445] *See Bd. of Trs. of State Univ. of N.Y.*, 492 U.S. 469; *see supra* Requirements Concerning Relevant State Entities' Agreed-upon Cost Allocation Methods section.

explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation does not compel transmission providers to utter phrases "repugnant to their moral, religious, and political beliefs,"[446] but instead simply requires that they explain their disagreement with Relevant State Entities as to the economic matter of how the cost of Long-Term Regional Transmission Facilities ought to be allocated.[447] Therefore, at most, the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation should be judged under the *Central Hudson* standard applied to regulations on commercial speech.[448] We find that this requirement satisfies *Central Hudson*, as it

[446] *Wooley*, 430 U.S. at 707.

[447] *Md. Shall Issue*, *Inc.*, 91 F.4th at 248.

[448] *Recht*, 32 F.4th at 409. While Indicated PJM TOs argue that either strict or intermediate scrutiny should apply to the requirement that transmission providers include in their compliance filings the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process agreed upon by Relevant State Entities, Indicated PJM TOs do not specify the level of constitutional scrutiny they believe should apply to the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation. Indicated PJM TOs Rehearing Request at 31-33. For the avoidance of doubt, we find that strict scrutiny is inapplicable to the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State

directly advances the Commission's substantial interest in ensuring that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920, which has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission Facilities,[449] and is "in proportion to" and not more extensive than is necessary to serve the Commission's substantial interest.[450]

### C. Definition of Relevant State Entities

#### 1. Order Nos. 1920 and 1920-A

131. In Order No. 1920, the Commission defined a "Relevant State Entity" as "any state entity responsible for electric utility regulation or siting electric transmission

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Agreement Process preferred by Relevant State Entities during the required consultation after the Engagement Period.

[449] Order No. 1920-A, 189 FERC ¶ 61,126 at P 692 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126).

[450] *See Bd. of Trs. of State Univ. of N.Y.*, 492 U.S. at 480 (quoting *In re R.M.J.*, 455 U.S. 191, 203 (1982)). As discussed above at note 359, regulations on commercial speech such as the requirement that transmission providers explain why they have chosen not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process preferred by Relevant State Entities during the required consultation need not be the least restrictive means of achieving the government's substantial interest. *Id.* Thus, the fact that Relevant State Entities could alternatively "file their own proposal under FPA section 206" has no bearing on the constitutionality of this requirement. Indicated PJM TOs Rehearing Request at 33.

facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state."[451] In response to comments on the NOPR, the Commission declined to expand the definition of Relevant State Entities to include additional entities, including electric cooperatives, and explained that providing state regulators with a formal opportunity to develop cost allocation methods in Long-Term Regional Transmission Planning could increase state support for Long-Term Regional Transmission Facilities that transmission providers select and that this may increase the likelihood that such facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable Commission-jurisdictional rates.[452] The Commission made clear, however, that nothing in Order No. 1920 diminishes the role of stakeholders that are not Relevant State Entities nor absolves transmission providers of any existing obligations that they may have to provide opportunities for stakeholder input.[453]

132. Order No. 1920 provided opportunities for Relevant State Entities to participate in Long-Term Regional Transmission Planning, including, but not limited to, the requirements that transmission providers in each transmission planning region:

(1) consult with and seek support from Relevant State Entities regarding the evaluation

[451] Order No. 1920, 187 FERC ¶ 61,068 at PP 44, 1355; *see also* Order No. 1920-A, 189 FERC ¶ 61,126 at P 701.

[452] Order No. 1920, 187 FERC ¶ 61,068 at P 1364.

[453] *Id.* P 1000.

process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional Transmission Facilities for selection;[454] (2) include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria;[455] and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.[456] The Commission declined to expand participation in the Engagement Period beyond Relevant State Entities but stated that other participants beyond Relevant State Entities may participate in the State Agreement Process, if agreed to by Relevant State Entities.[457]

133. In Order No. 1920-A, the Commission recognized the valuable insight that municipal electric regulatory bodies and non-public utilities provide as stakeholders in Commission-sanctioned processes but declined requests to expand the definition of Relevant State Entity to encompass other entities.[458] In support of its decision, the Commission emphasized that state entities responsible for electric utility regulation or

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[454] *Id.* P 994.

[455] *Id.* P 1012.

[456] *Id.* P 1354.

[457] *Id.* PP 1364 & n.2914, 1402, 1416, 1421.

[458] Order No. 1920-A, 189 FERC ¶ 61,126 at PP 700-701.

siting electric transmission facilities are uniquely situated to influence whether or not a Long-Term Regional Transmission Facility reaches completion.[459] The Commission continued to find that "regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders—in particular, a state regulator responsible for permitting transmission facilities—do not perceive the regional transmission facilities' value as commensurate with their costs."[460] However, the Commission did not make a determination on whether an individual state's laws, regulations, and/or policies, or inclusion in a larger association of regulators, deem any particular entity to be a Relevant State Entity, though the Commission noted that state law may be a persuasive or dispositive factor in such determinations.[461]

### 2. Rehearing Requests

134. NRECA requests that the Commission modify the definition of Relevant State Entity to include any entity that establishes or regulates electric rates under state law, in light of Order No. 1920-A's modifications to the roles played by Relevant State Entities.[462] NRECA states that Order No. 1920-A substantially changes the final rule by creating expanded and additional opportunities for Relevant State Entities to influence and determine Long-Term Regional Transmission Planning and associated cost allocation

[459] *Id.* P 701 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1364).

[460] *Id.* P 700 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1364).

[461] *Id.* P 703.

[462] NRECA Rehearing Request at 12.

methods, such as requiring incorporation of input from Relevant State Entities in developing Long-Term Scenarios and requiring compliance filings to include any Long-Term Regional Transmission Cost Allocation Method or State Agreement Process agreed upon by Relevant State Entities.[463]

135. NRECA argues that Order No. 1920-A's modifications to the final rule are incomplete, and the Commission's goal of giving the entities that represent electric consumers under state law a greater voice in transmission planning and cost allocation decisions is not met, because the order does not ensure comparable representation of all electric consumers in a state.[464] NRECA points out that many state public utility commissions do not regulate the rates of all electric utilities in their respective states and that often electric cooperatives establish their rates independently of their state's utility commission. NRECA asserts that the Commission arbitrarily and without explanation excluded or allowed transmission planning regions to exclude the representatives of some electric consumers from the more robust process created by Order No. 1920-A.[465] NRECA states that the Commission's definition of Relevant State Entity in Order Nos. 1920 and 1920-A is not bound by statute or prior regulations, as the Commission crafted this definition for the purpose of Order Nos. 1920 and 1920-A.[466]

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[463] *Id.* at 5-8.

[464] *Id.* at 9.

[465] *Id.* at 10.

[466] *Id.* at 11-12 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 704).

136. NRECA argues that the FPA's prohibition on undue discrimination or preference extends to practices affecting jurisdictional rates as well as the rates themselves.[467] Accordingly, NRECA claims that Order No. 1920-A is arbitrary, capricious, not in accordance with law, and not the product of reasoned decision-making, as it does not require transmission providers to provide the expanded opportunities for participation in transmission planning and cost allocation decision-making processes on a nondiscriminatory and non-preferential basis to all entities "responsible for electric utility regulation" under state law.[468]

137. Finally, NRECA argues that the Commission should clarify or modify Order No. 1920-A to require transmission providers to demonstrate in their compliance filings how they are ensuring that all entities that establish or regulate electric rates under state law will be treated without undue discrimination or preference.[469]

### 3. Commission Determination

138. We are not persuaded by NRECA's request to expand the definition of Relevant State Entity to include any entity that establishes or regulates electric rates under state law.[470] As discussed in Order No. 1920-A, while we recognize the important role that many stakeholders, including municipal electric regulatory bodies and non-public utility

[467] *Id.* at 13.

[468] *Id.* at 4, 13-14.

[469] *Id.* at 15.

[470] *Id.* at 12.

entities, play in Commission-sanctioned processes, we continue to find that the definition of Relevant State Entities should encompass only state entities responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.[471]

139. In Order No. 1920-A, the Commission reaffirmed and enhanced the important role of states in the Long-Term Regional Transmission Planning process by recognizing that meaningful engagement with states is critical to the success of the Long-Term Regional Transmission Planning reforms established in Order No. 1920.[472] Specifically, the Commission in Order No. 1920-A better integrated states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future.

140. Importantly, however, this strengthened role of Relevant State Entities does not limit or inhibit other entities from engaging robustly via the Commission's or state's standard procedures for public participation. We also reiterate that Order No. 1920 allows other participants, including the municipal electric regulatory bodies and non-public utility entities mentioned above that do not otherwise meet the definition of a Relevant State Entity, to participate in a State Agreement Process, if agreed to by

[471] Order No. 1920-A, 189 FERC ¶ 61,126 at P 701.

[472] *Id.* P 3.

Relevant State Entities.[473] Further, we emphasize that nothing in Order No. 1920 or Order No. 1920-A prevents transmission providers generally from consulting or working closely with stakeholders in addition to Relevant State Entities to ensure the success of Long-Term Regional Transmission Planning. Indeed, we welcome such collaboration.

141. We disagree with NRECA's argument that the definition of Relevant State Entity allows for unduly discriminatory and preferential transmission planning and cost allocation practices by not expressly encompassing any entity that establishes or regulates electric rates under state law.[474] As discussed in Order No. 1920, allowing Relevant State Entities to better realize Long-Term Regional Transmission Facilities' value through an enhanced role in the regional transmission planning process greatly increases the likelihood of their support for those facilities. Relevant State Entities play a unique role in that they retain a variety of authorities that are integral to the success of Long-Term Regional Transmission Planning.[475] Therefore, the support of Relevant State Entities may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays, and thus better ensures just and reasonable Commission-jurisdictional rates.[476] Additionally, we reiterate that we are not excluding

[473] Order No. 1920, 187 FERC ¶ 61,068 at PP 1364 n.2914, 1402; Order No. 1920-A, 189 FERC ¶ 61,126 at P 701.

[474] NRECA Rehearing Request at 13.

[475] Order No. 1920, 187 FERC ¶ 61,068 at P 1000.

[476] *Id.* P 1364.

any specific entities from this process; instead, we make no findings regarding whether any individual municipal electric regulatory body or non-public utility entity meets the definition of a Relevant State Entity, as those determinations properly rest with entities in a state, based upon their interpretation of their state laws.[477]

142. We further are not persuaded by NRECA's request for a requirement that transmission providers demonstrate in their compliance filings how they are ensuring that all entities that establish or regulate electric rates under state law will be treated without undue discrimination or preference.[478] Nothing in Order No. 1920 diminishes the role of stakeholders that are not Relevant State Entities, nor absolves transmission providers of any existing obligations that they may have to provide opportunities for stakeholder input.[479]

### D. Other Cost Allocation Issues

#### 1. Order Nos. 1920 and 1920-A

143. In Order No. 1920, the Commission found that there is substantial evidence to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis, and that the absence of such processes is resulting in piecemeal transmission expansion to address

[477] Order No. 1920-A, 189 FERC ¶ 61,126 at P 703.

[478] NRECA Rehearing Request at 15.

[479] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1000.

relatively near-term transmission needs. The Commission found that the status quo approach results in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates.[480]

144. The Commission concluded that revisions to the Commission's regional transmission planning and cost allocation requirements are necessary to ensure that Commission-jurisdictional rates, terms, and conditions are just, reasonable, and not unduly discriminatory or preferential. The Commission found that, absent the reforms instituted by Order No. 1920, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development.[481]

145. The Commission therefore concluded, based on the record in the proceeding, that there is substantial evidence to support the conclusion that deficiencies in the Commission's existing regional transmission planning and cost allocation requirements are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential.

146. As relevant here, the Commission specifically found that the Commission's current cost allocation requirements, which were designed and established in the context

[480] *Id.* P 112.

[481] *Id.* P 113.

of existing Order No. 1000 regional transmission planning processes, are insufficient to appropriately allocate costs associated with regional transmission facilities that are selected in accordance with the new Long-Term Regional Transmission Planning requirements that the Commission established in Order No. 1920. Accordingly, the Commission found that it is both necessary and appropriate to establish specific cost allocation requirements that are tailored to the Long-Term Regional Transmission Planning reforms in Order No. 1920.[482]

147. In Order No. 1920-A, the Commission responded to rehearing requests that argued that the Commission had failed to satisfy its FPA section 206 burden to demonstrate that existing Order No. 1000 regional transmission planning and cost allocation processes are unjust, unreasonable, or unduly discriminatory or preferential[483] and sustained its Order No. 1920 determinations as to its action under the first prong of FPA section 206.[484] As relevant here, the Commission continued to find that the Commission made adequate findings and marshalled substantial evidence under the first prong of FPA section 206, and that it found rehearing petitioners' arguments to the contrary to be unpersuasive. The Commission concluded that the evidence on which it relied—both empirical and generic

[482] *Id.* P 126.

[483] *See* Order No. 1920-A, 189 FERC ¶ 61,126 at PP 70-71 (describing rehearing requests received from Designated Retail Regulators, Undersigned States, Arizona Commission, and Industrial Customers challenging the sufficiency under the first prong of FPA section 206 of the evidence relied upon by the Commission in Order No. 1920).

[484] *Id.* P 72.

factual predictions—was more than sufficient to meet its evidentiary burden under FPA section 206.[485]

### 2. Rehearing Requests

148. Indicated PJM TOs and SPP TOs argue that the Commission failed to make an adequate finding under the first prong of FPA section 206 that substantial evidence supports the determination that existing regional cost allocation methods are unjust and unreasonable.[486] Indicated PJM TOs state that FPA section 206 requires the Commission to prove that each rate or practice affecting such rate that it seeks to change is unlawful based on substantial evidence.[487] Indicated PJM TOs assert that "[t]he Commission makes several findings that *the existing regional planning process* is unjust and unreasonable but makes no findings that the existing *regional cost allocation method[]* is unjust and unreasonable."[488] Indicated PJM TOs aver that the findings in Order Nos. 1920 and 1920-A that an existing rate is unjust and unreasonable are confined to the transmission planning process, and that the Commission "simply assume[d]" that existing

[485] *Id.* PP 72-83.

[486] Indicated PJM TOs Rehearing Request at 7, 23-27; SPP TOs Rehearing Request at 7-8, 21-28.

[487] Indicated PJM TOs Rehearing Request at 24-25 (citing 16 U.S.C. 825*l*(b); *Emera Maine*, 854 F.3d at 24; *South Carolina*, 762 F.3d at 56-69).

[488] *Id.* at 5; *see id.* at 7 (emphasis in original).

regional cost allocation methods are unjust and unreasonable on the basis of evidence that existing regional transmission planning processes are unjust and unreasonable.[489]

149. Indicated PJM TOs argue that the Commission justified its decision by stating that existing cost allocation methods do not properly reflect the benefits to be considered in the new Order No. 1920 long-term transmission planning requirements and that there is no process to engage states in the development of regional cost allocation methods, but there is not substantial evidence in the record or analysis supporting these determinations.[490] Indicated PJM TOs argue that the Commission acknowledged that it may be just and reasonable to continue to apply existing regional cost allocation methods, that the Commission cannot conclude that a rate is unjust and unreasonable simply because it differs from the rate the Commission seeks to impose, and that the Commission has shifted the burden onto public utilities to demonstrate their cost allocation methods are consistent with the requirements of Order No. 1920.[491] Indicated PJM TOs contend that because the Commission has not carried its burden under the first prong of FPA section 206 with respect to the cost allocation methods for Long-Term

[489] *Id.* at 24 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at PP 47 & n.80, 52 & n.92).

[490] *Id.* at 25 (arguing that the Commission failed to consider the example of whether PJM's cost allocation method for multi-driver projects would be appropriate under Order No. 1920 or whether PJM's existing State Agreement Approach provided sufficient state involvement in cost allocation processes).

[491] *See id.* at 26 (citing *Emera Maine*, 854 F.3d at 22-26; Order No. 1920-A, 189 FERC ¶ 61,126 at P 714).

Regional Transmission Facilities, any proposals related to such cost allocation methods must be made and considered under FPA section 205 and approved if just and reasonable.[492]

150. SPP TOs assert that Order Nos. 1920 and 1920-A do not present substantial evidence establishing a causal link between the Commission's changes to its transmission planning requirements and the need for replacement rates on cost allocation.[493] SPP TOs acknowledge that the Commission made such findings in Order Nos. 1920 and 1920-A but contend that these findings fall short of statutory requirements.[494] Specifically, they argue that "[t]he creation of new benefits in the transmission planning process does not support the Commission's conclusion that a new transmission cost allocation scheme is also needed" because costs need not be allocated with exacting precision and there is more than one just and reasonable rate, such that existing rates may still be just and reasonable.[495] Further, SPP TOs contend that the Commission disavowed in Order No. 1920 any causal link between the benefits required to be used and measured for planning purposes and the proposed replacement rate such that an acceptable cost allocation method need not include a mechanism for allocating the costs of Long-Term

[492] *Id.* at 26-27 (citing 16 U.S.C. 824d(e); *Sw. Power Pool, Inc.*, 189 FERC ¶ 61,128, at P 60 n.230 (2024)).

[493] SPP TOs Rehearing Request 22-23; *see also id.* at 7-8.

[494] *Id.* at 21-22 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 113-114; Order No. 1920-A, 189 FERC ¶ 61,126 at PP 34-124, 652).

[495] *Id.* at 23-24.

Regional Transmission Facilities in line with the measurement of benefits. Therefore, SPP TOs argue, the Commission was required to make additional factual findings, such as showing that Order No. 1920's transmission planning requirements would cause existing cost allocation methods to fail to meet the cost causation principle.[496]

151. SPP TOs assert that the holding in *South Carolina* that "'substantial evidence' is not limited to empirical evidence and may include generic factual predictions"[497] does not support the Commission's decision because "the Commission fails to show any support for 'generic factual predictions' related to supposed cost allocation deficiencies."[498] SPP TOs further contend that the Commission's discussion of the need for reform in Order Nos. 1920 and 1920-A does not support a finding under the first prong of FPA section 206 as to cost allocation, because the relevant material in the record addresses the need for improved transmission planning, not cost allocation.[499] In addition, SPP TOs argue that the Commission does not cite any record evidence that existing cost allocation methods fail to adequately consider the views of states, does not support the need for a dedicated process through which states have the opportunity to participate in regional

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[496] *Id.*

[497] *South Carolina*, 762 F.3d at 65.

[498] SPP TOs Rehearing Request at 25 (discussing Order No. 1920, 187 FERC ¶ 61,068 at PP 113-114, and asserting that "[b]oth paragraphs merely state conclusions regarding the need for cost allocation reforms").

[499] *Id.* at 25-26 (discussing Order No. 1920-A, 189 FERC ¶ 61,126 at P 77, and associated record material, as well as Order No. 1920, 187 FERC ¶ 61,068 at PP 117, 121, 123).

cost allocation methods, and does not show that existing methods are insufficient to appropriately allocate costs in this context.[500]

### 3. Commission Determination

152. FPA section 313(a) provides that a party aggrieved by an order issued by the Commission "may apply for a rehearing within thirty days after the issuance of such order."[501] That provision further requires that "[t]he application for rehearing shall set forth specifically the ground or grounds upon which such application is based."[502] An aggrieved party is entitled to one opportunity to ask the Commission to reconsider a decision.[503] Arguments that are not made at the first opportunity cannot be made later unless there is reasonable ground for failure to do so.[504] Successive rehearing requests

[500] *Id.* at 27-28 (citing Order No. 1920-A, 189 FERC ¶ 61,126 at P 83; Order No. 1920, 187 FERC ¶ 61,068 at P 126).

[501] 16 U.S.C. 825*l*(a); *see also* 18 CFR 385.713(b) (rehearing request must be filed not later than 30 days after issuance of a final decision or order).

[502] 16 U.S.C. 825*l*(a).

[503] *See Tenn. Gas Pipeline Co. v. FERC*, 871 F.2d 1099, 1110 n.18 (D.C. Cir. 1989) ("[I]f a party does not raise an argument *that it could have raised* in its first petition for review of a Commission action, it cannot preserve that argument for judicial review simply by filing a second petition for rehearing from a subsequent Commission order which implicates the same action." (emphasis in original)); *Smith Lake Improvement & Stakeholders Ass'n*, 809 F.3d at 58 (holding that, when a Commission rehearing order does not alter an aspect of the underlying order, seeking further rehearing as to that unchanged aspect does not toll the 60-day period for requesting judicial review).

[504] *Columbia Gas Transmission Corp. v. FERC*, 477 F.3d 739, 741-42 (D.C. Cir. 2007); *Appalachian Power Co.*, 149 FERC ¶ 61,137, at P 8 (2014); *accord N.C. Utils. Comm'n v. FERC*, 741 F.3d 439, 449 (4th Cir. 2014).

are only proper when the order on rehearing modifies the result reached in the original order in a manner that gives rise to a "wholly new objection."[505]

153. Here, Indicated PJM TOs did not request rehearing of this aspect of Order No. 1920,[506] and SPP TOs did not request rehearing of Order No. 1920. Nor have Indicated PJM TOs or SPP TOs provided a reasonable ground for their failure to timely raise their objections to Order No. 1920's findings under the first prong of FPA section 206. Nevertheless, the concerns they raise regarding the Commission's findings under the first prong of FPA section 206 and sufficiency of evidence to support its exercise of authority in Order No. 1920[507] were thoroughly addressed in Order No. 1920-A,[508] which sustained Order No. 1920's outcome on this issue.[509] The

[505] *Appalachian Power Co.*, 149 FERC ¶ 61,137 at P 8 (citing, *inter alia*, *S. Nat. Gas Co. v. FERC*, 877 F.2d 1066, 1073 (D.C. Cir. 1989)); *see also Smith Lake Improvement & Stakeholders Ass'n* , 809 F.3d at 58 (finding, in a case "where the result did not change on first rehearing and petitioner sought a second rehearing nonetheless," that "there can be no dispute that [precedent] precludes judicial review of an untimely petition").

[506] *See generally* Indicated PJM TOs June 12, 2024 Rehearing Request.

[507] Indicated PJM TOs Rehearing Request at 23-27; SPP TOs Rehearing Request at 21-28.

[508] *See* Order No. 1920-A, 189 FERC ¶ 61,126 at PP 70-71 (describing rehearing requests received from Designated Retail Regulators, Undersigned States, Arizona Commission, and Industrial Customers challenging the sufficiency under the first prong of FPA section 206 of the evidence relied upon by the Commission in Order No. 1920).

[509] *Id.* P 72 ("We continue to find that the Commission made adequate findings under the first prong of FPA section 206 and marshalled substantial evidence to support those findings. We are therefore not persuaded by rehearing parties' arguments to the contrary."). *See Appalachian Power Co*., 149 FERC ¶ 61,137 at P 10 n.18 ("An 'improved rationale' for the Commission's underlying decision ... does not support a

reasoning therein fully responds to the challenges on this issue raised here by the Indicated PJM TOs and SPP TOs.

154. Accordingly, we find that successive requests for rehearing of this determination in Order No. 1920 do not lie, and SPP TOs' arguments regarding the sufficiency of the Commission's findings in Order No. 1920,[510] as well as both Indicated PJM TOs' and SPP TOs' objections to the sufficiency of statements made in Order No. 1920-A that merely sustain Order No. 1920,[511] are rejected.[512]

## IV. Document Availability

155. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the

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second request for rehearing." (citing *Erie Boulevard Hydropower, L.P.*, 118 FERC ¶ 61,196, at P 8 (2007))); *Smith Lake Improvement & Stakeholders Ass'n*, 809 F.3d at 56-57 ("We have made clear that a second rehearing petition must be filed if—and only if—the first rehearing order 'modifie[d] the results of the earlier one in a significant way.' We subsequently explained that means a change in the 'outcome,' not merely a change in reasoning." (internal citations omitted)).

[510] *See* SPP TOs Rehearing Request at 23-24 nn.64-65, 25 nn.68-70, 26-27 nn.77-79.

[511] *See* Indicated PJM TOs Rehearing Request at 24 nn.89-91, 25 n.94; SPP TOs Rehearing Request at 22-23 nn.58-60, 24-25 n.67, 25-26 nn.71-73, 26 nn.75-76, 27 nn.80-82. *See also* Indicated PJM TOs Rehearing Request at 5 ("*Order No. 1920-A* fails to make the finding required by the first prong and to establish a replacement rate under the second prong." (emphasis added)).

[512] *See NEXUS Gas Transmission, LLC*, 187 FERC ¶ 61,098, at P 13 (2024) (citing *Calpine Corp.*, 173 FERC ¶ 61,061, at P 144 (2020) (rejecting an argument as an impermissible request for rehearing of an order on rehearing)).

contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov).

156. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

157. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

## V. Effective Date

158. The effective date of the document published on December 6, 2024 (89 FR 97,174), is confirmed: January 6, 2025.

By the Commission. Commissioner See is not participating.

( S E A L )

Carlos D. Clay,
Deputy Secretary.

NOTE: The following appendix will not appear in the Code of Federal Regulations.

Appendix A: Abbreviated Names of Rehearing Petitioners

| Abbreviation | Rehearing Party(ies) |
|---|---|
| Developers Advocating Transmission Advancements | Ameren Services Company; Eversource Energy; Exelon Corporation; ITC Holdings Corp., National Grid USA; Xcel Energy |
| EEI | Edison Electric Institute |
| Indicated PJM TOs | American Electric Power Service Corporation on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc.; the Dayton Power and Light Company; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation on behalf of its affiliates Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Delmarva Power & Light Company, PECO Energy Company, and Potomac Electric Power Company; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| | Interstate Transmission LLC, West Penn Power Company, Potomac Edison Company, Monongahela Power Company, Keystone Appalachian Transmission Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; Rockland Electric Company; and UGI Utilities Inc. |
| MISO TOs | AEP Indiana Michigan Transmission Company; Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; Lafayette Utilities System; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc. |

| Abbreviation | Rehearing Party(ies) |
|---|---|
| NRECA | National Rural Electric Cooperative Association |
| SPP TOs | American Electric Power Service Corporation, on behalf of Southwestern Electric Power Company, Public Service Company of Oklahoma, AEP Oklahoma Transmission Company, Inc., and AEP Southwestern Transmission Company, Inc.; the Evergy Companies; and Xcel Energy Services Inc. on behalf of Southwestern Public Service Company |
| WestConnect CTOs | Colorado Springs Utilities; Imperial Irrigation District; Los Angeles Department of Water and Power; Platte River Power Authority; Sacramento Municipal Utility District; Salt River Project Agricultural Improvement and Power District; and the Transmission Agency of Northern California |
| WIRES | WIRES |

Document Content(s)

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# 2025 TRANSMISSION PLANNING AND DEVELOPMENT REPORT CARD

## ASSESSING PROGRESS AND SHORTFALLS AS DEMAND ACCELERATES NATIONWIDE

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Americans for a Clean Energy Grid

*Americans for a Clean Energy Grid (ACEG) is a non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high-capacity grid.*

**FEBRUARY 2026**

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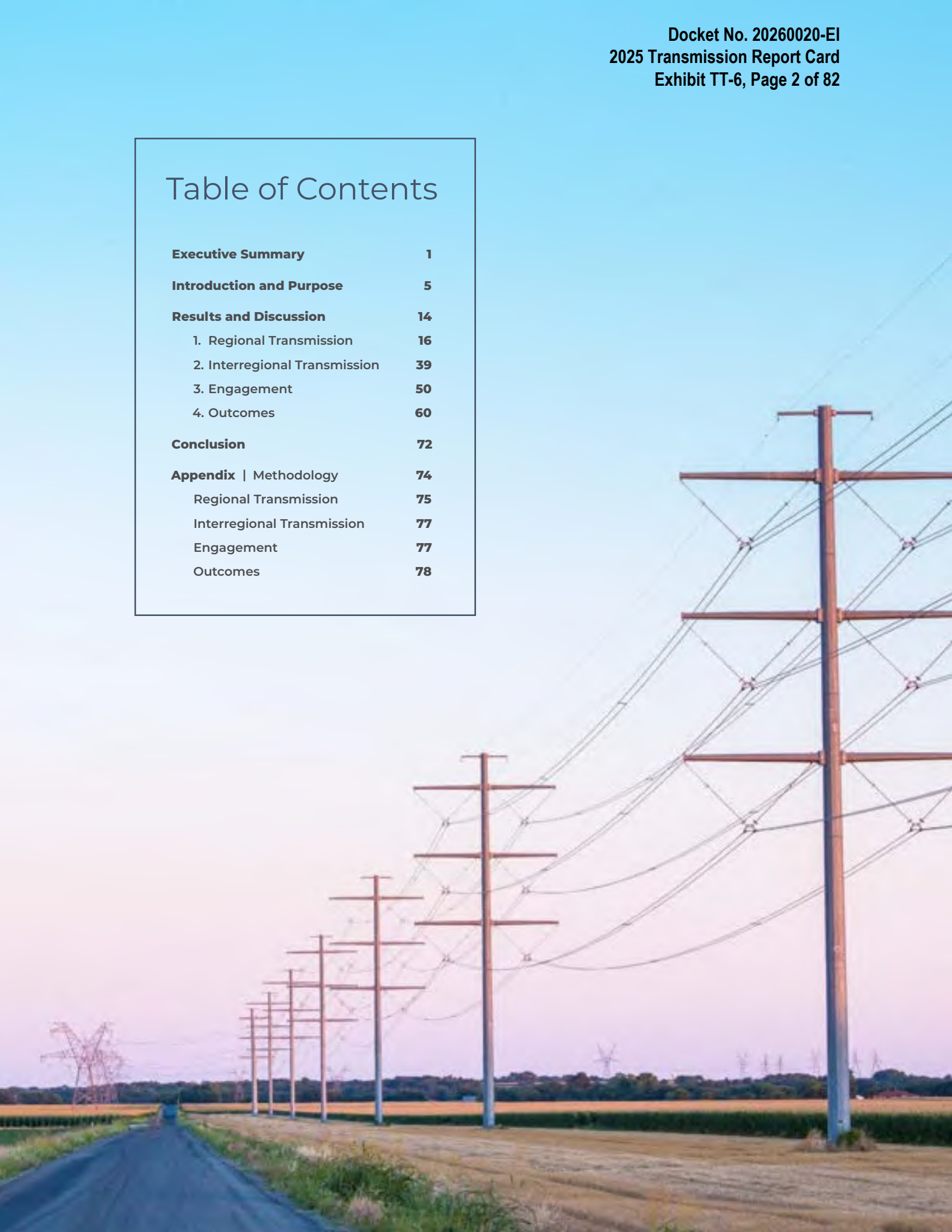
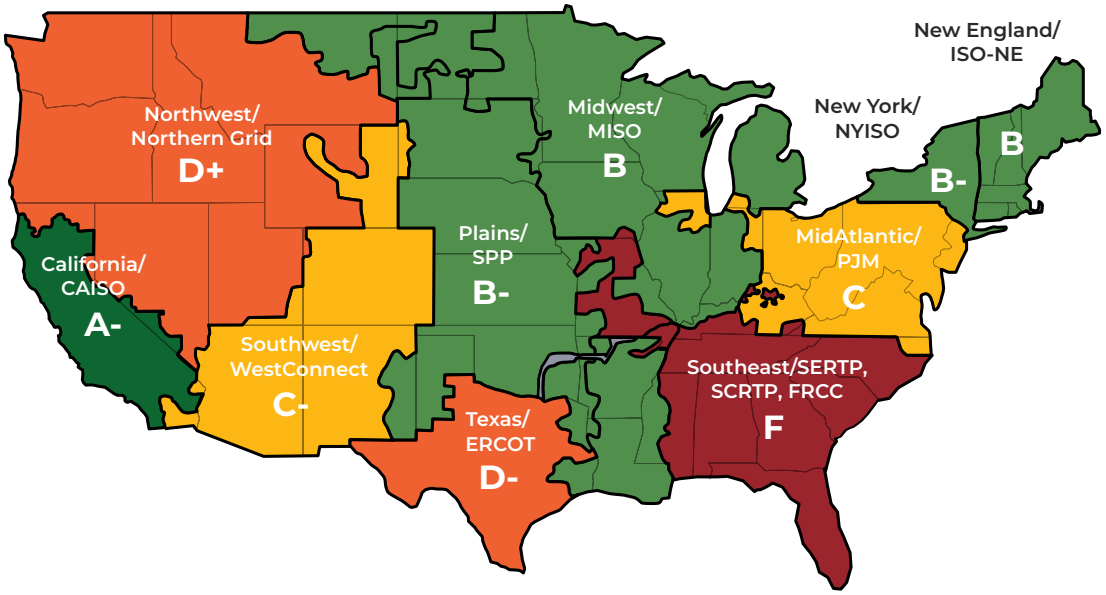


# Executive Summary

The 2025 Transmission Planning and Development Report Card provides an updated assessment of U.S. transmission planning and development across ten regions. The first edition of the Report Card was published in 2023. **Overall, this edition of the Report Card shows incremental improvement in transmission planning across most of the regions, driven largely by reforms to regional planning. However, many regions continue to fall well short of best practices, and progress remains uneven relative to the scale and urgency of today's transmission needs.** Accelerating electricity demand — driven by data centers, manufacturing growth, and electrification — is increasing the importance of forward-looking transmission planning, compressing planning timelines, and raising the stakes for regions that continue to rely on incremental or reactive approaches.

The Federal Energy Regulatory Commission's (FERC) Order No. 1920, which requires regions to begin adopting long-term planning best practices, helped drive improvements, particularly in regional planning for a few regions, even before full compliance is finalized. At the same time, widespread compliance extensions for Order No. 1920 mean many of the rule's full benefits may not be realized for years. As a result, current grades should be understood as a snapshot of progress underway rather than an endpoint.

**FIGURE ES-1** Summary of overall grades by region



This edition of the Report Card places greater emphasis on interregional transmission planning, reflecting an established body of research demonstrating the significant reliability, affordability, and resilience benefits interregional investments can deliver. While some interregional transmission planning is being conducted through state coordination and voluntary planning efforts and some development is advancing by independent/merchant projects, these efforts remain largely voluntary. Across most regions, interregional coordination relies on reliability-focused studies rather than proactive, scenario-based planning with durable selection and cost-allocation frameworks. As a result, interregional transmission remains one of the weakest elements of the national planning landscape, with planned capacity generally falling short of estimated need.

Regional performance varies across the four metrics evaluated. Several regions — **California**, the **Midwest**, and the **Plains** — continue to demonstrate the benefits of proactive, long-term regional planning. Coupled with developments in interregional transmission planning, these regions' grades continued to improve. Highlighted in this report is the Consolidated Planning Process advanced by the Southwest Power Pool (SPP) in the Plains region, which — once approved by FERC — will be an important and significant reform that merges the region's planning process, including transmission and generator interconnection planning.

**New England** and the **Mid-Atlantic** have both shown meaningful improvement, driven by recent long-term regional planning reforms. The Mid-Atlantic improved its regional planning through Order No. 1920-related long-term planning reforms. Most of New England, New York, and some of the Mid-Atlantic have also increased state engagement on interregional transmission planning through the Northeast States Collaborative on Interregional Transmission.

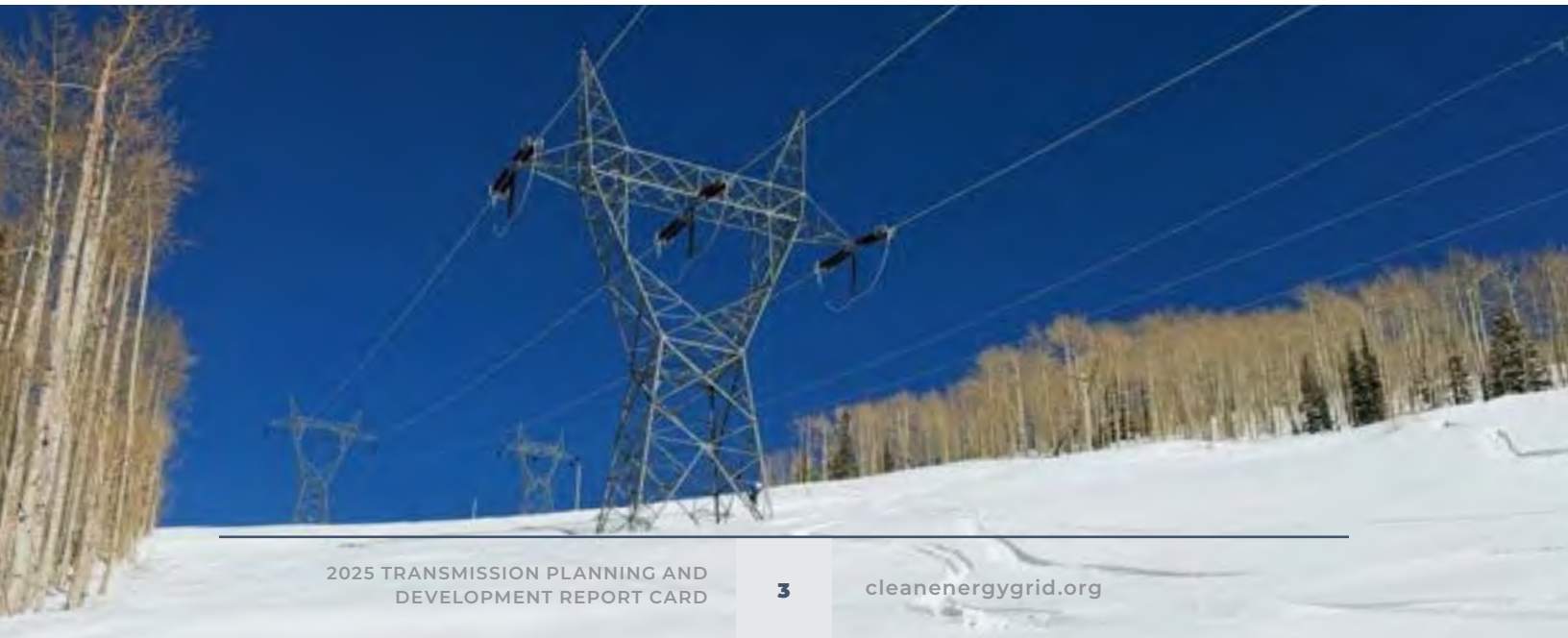
At the same time, many regions — including all of the non-Regional Transmission Organization (RTO) regions — continue to face significant gaps in both regional and interregional planning frameworks. In these regions, transmission development often occurs through individual utility investments or ad hoc coordination rather than durable, region-scale planning processes, limiting the ability to fully capture system-wide benefits. That said, in the West, the **Northwest** and **Southwest** along with California are participating in the Western Transmission Expansion Coalition (WestTEC), a voluntary, west-wide transmission planning process that has broad stakeholder participation and is currently one of the best interregional transmission planning practices in the country.

For the evaluation, the Report Card combines qualitative metrics (regional and interregional planning and engagement best practices) with quantitative outcomes (includ-

ing recently constructed high-capacity transmission, planned transmission projects, and congestion). The evaluation assesses performance at the regional level rather than assigning responsibility to any single institution. This practice recognizes that outcomes reflect the actions of multiple entities, including regional planning organizations, utilities, states, and other stakeholders. Grades are best interpreted as a benchmark against established best practices rather than a definitive verdict, since any grading framework cannot be completely objective. All grades are provided in Figs. ES-1 and ES-2, including a comparison with grades from the 2023 Report Card.

**FIGURE ES-2** Summary of individual grade components for each region

| REGION | REGIONAL PLANNING | INTERREGIONAL PLANNING | ENGAGEMENT | OUTCOMES | OVERALL GRADE | | 2023 GRADE |
|---|---|---|---|---|---|---|---|
| **California** | A+ | B- | A- | A | **A-** | ↑ | **B** |
| **Northwest** | F | C | F | B+ | **D+** | ↑ | **D** |
| **Southwest** | D+ | C | F | B- | **C-** | ↑ | **D-** |
| **Texas** | C | F | B | C- | **D-** | ↓ | **D+** |
| **Plains** | A | C | B | B- | **B-** | ↑ | **C+** |
| **Midwest** | A | B- | B+ | C | **B** | ↔ | **B** |
| **Southeast** | F | F | F | F | **F** | ↔ | **F** |
| **Mid-Atlantic** | B | D+ | B | C- | **C** | ↑ | **D+** |
| **New York** | B+ | C+ | A- | C- | **B-** | ↑ | **C+** |
| **New England** | B | C | A- | A | **B** | ↑ | **D+** |



Regions across the country are generally making progress on planned high-capacity regional transmission, which is encouraging but not yet decisive. Many regions have planned regional transmission capacity broadly consistent with the Department of Energy's (DOE) 2023 National Transmission Needs Study ("Needs Study"). However, load growth projections have risen since that study was released — resulting in lower targets than what will actually be needed if load growth forecasts are correct. Additionally, significant siting, permitting, and implementation challenges remain, particularly for interregional projects, and could affect whether planned investments are ultimately delivered. In all, we believe the 2023 Needs Study provides a conservative target to which we compare regional progress.

To earn an overall "A," regions need to incorporate the following best practices into regional and interregional planning process that considers regional needs holistically: proactive 20-year load and generation forecasts, robust scenario analysis including extreme weather, multi-value benefits analysis, portfolio development, consideration of all business models and Advanced Transmission Technologies, integration with other planning processes, and durable selection and cost allocation frameworks. Regions must also have representation from states and incorporation of state policies, robust engagement with stakeholders, and plan for and build transmission at the necessary pace.

Taken together, the Report Card finds that regional transmission planning reforms related to Order No. 1920 are beginning to take hold, and that early progress is visible in several regions. However, accelerating demand growth and persistent weaknesses in interregional planning mean that incremental improvements alone will not be sufficient. Future Report Cards will be able to assess whether planned projects are built, whether voluntary interregional efforts mature into durable planning frameworks, and whether regions with lower grades are able to translate state and utility-level activity into comprehensive, region-scale outcomes that meet emerging system needs.

# Introduction and Purpose

**This Report Card is the third installment evaluating the status of transmission planning and development around the country.**

In the 2023 Report Card, we established baseline grades for regional transmission planning and development outcomes, laid out best practices, and provided a brief overview of the regulatory context and history of regional planning and its benefits.[1] Our second installment[2] did not update grades, but instead, it offered an interim update as FERC had just issued Order No. 1920 to reform regional long-term transmission planning. Several reforms and initiatives across the regions were also underway but not finalized, so their outcomes remained uncertain. In this third installment, we updated regional planning grades, given the requirements in Order No. 1920, and add a new focus on interregional transmission, engagement with stakeholders, and outcomes.

**Co-optimized transmission and generation planning delivers the most system savings to consumers.**

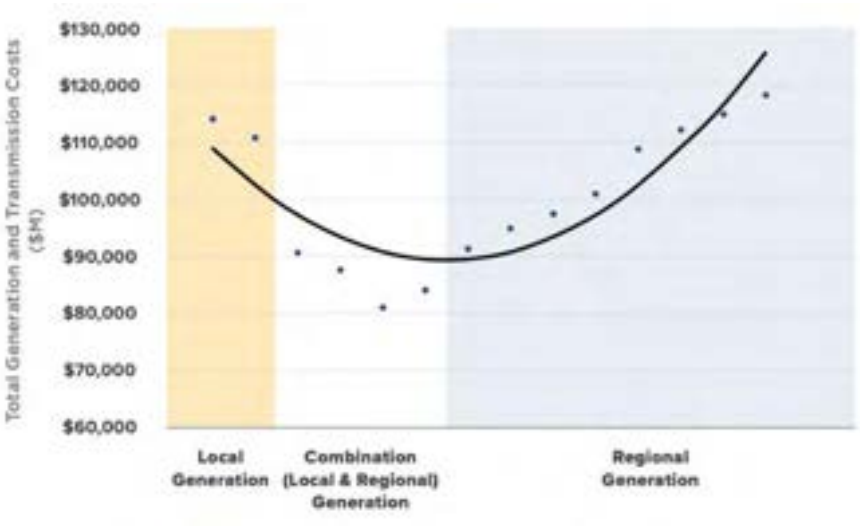
Proactive, holistic planning of large-scale transmission has repeatedly been shown to yield the most efficient investments for consumers. In particular, planning that co-optimizes generation resources and the transmission system delivers the lowest overall power-system costs. In its Multi-Value Planning process, the Midcontinent Independent System Operator (MISO) illustrated this with the 'smile curve' (*see Fig. 1*), which shows that optimizing between local and regional generating resources, together with the transmission needed to connect them, minimizes total system cost while maintaining reliability.[3]

1 *See* Americans for a Clean Energy Grid (ACEG) and Grid Strategies, *Transmission Planning and Development Regional Report Card (Jun. 2023),* https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf ("2023 Report Card").

2 *See* ACEG and Grid Strategies, *2024 State of Regional Transmission Planning (Oct. 2024),* https://cleanenergygrid.org/wp-content/uploads/2024/10/ACEG_2024-State-of-Regional-Transmission-Planning.pdf ("2024 Interim Report Card").

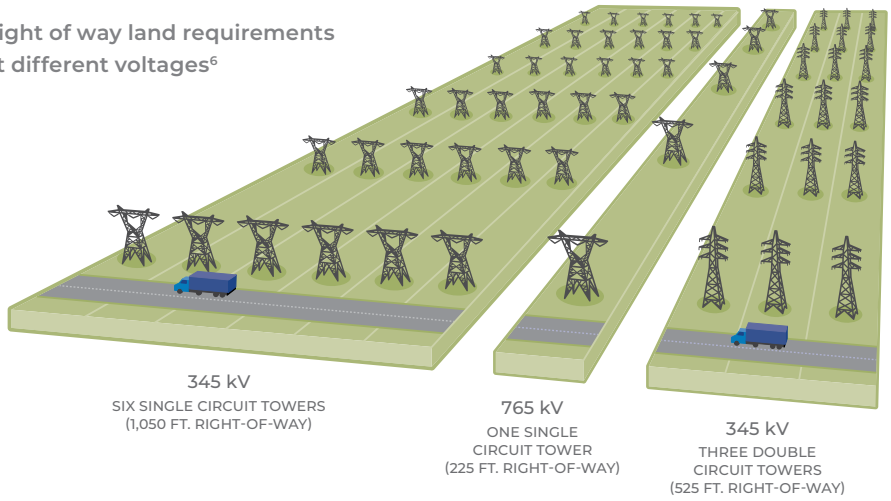
3 MISO, MTEP17 MVP Triennial Review, at 31 (Sept. 2017), https://cdn.misoenergy.org/MTEP17 MVP Triennial Review Report117065.pdf ("MTEP17").

**FIGURE 1** Optimizing transmission and generation delivers lowest overall system costs for consumers[4]




Many of these benefits arise from the substantial economies of scale achieved by higher-voltage lines (*see Fig. 2*). Compared with a 230-kilovolt (kV) line, a 765-kV line can deliver roughly six to ten times as much power while requiring only one-fifth the land for a right-of-way. Additionally, a 765-kV line can deliver power at roughly 75% lower cost on a per-unit-of-power-delivered basis than a 230-kV line.[5]

**FIGURE 2** Right of way land requirements at different voltages[6]




4 *Id.*

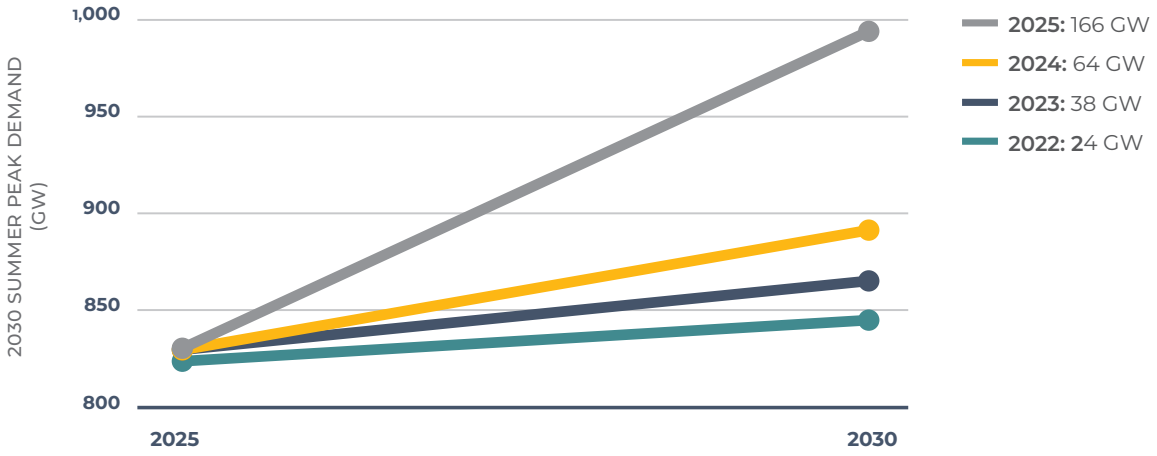
5 See MISO, Transmission Cost Estimation Guide for MTEP24 (May 2024), https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf ("2024 Transmission Cost Estimation Guide").

6 See 2024 Transmission Cost Estimation Guide; *See also* American Electric Power, "Experience with EHV Transmission Up to 765kV, 3 (Jun. 2023), https://www.ercot.com/files/docs/2023/06/27/7_AEP%20EHV%20Experience_AEP_Wilcox_20230626.pdf.

## Load growth is increasing the need for new transmission capacity.

In the first edition of the Report Card, we highlighted multiple drivers of new transmission capacity needs across the country, including an aging grid, building and transportation electrification, more frequent extreme weather, and a backlog of lower-cost generation seeking interconnection. Since then, growth in electricity demand, particularly from data centers and new manufacturing, has emerged as a primary driver of additional transmission needs. Year-over-year load growth expectations continue to rise. Grid Strategies' updated summary of nationwide peak-load forecasts shows that in just three years, the five-year load-growth forecast increased more than sixfold, from 24 GW to 150 GW (*see Fig. 3*).[7]

**FIGURE 3** 5-year nationwide summer peak load growth[8]




Surging load growth is also beginning to influence transmission construction. According to FERC's 2024 State of the Market Report, load growth was the second-largest driver of new transmission, after reliability needs, with approximately 1,000 miles of new facilities placed in service in 2024 due to load growth.[9] The miles of load-growth-driven transmission energized in 2024 exceeded those added in both 2023 and 2022.[10]

7 Grid Strategies, *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, 3 (Dec. 2025) https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf ("Grid Strategies 2025 Load Growth Report").

8 *Id.*

9 Federal Energy Regulatory Commission (FERC), *2024 State of the Markets, at 32-34 (Mar. 2025)*, https://www.ferc.gov/media/state-markets-report-2024.

10 FERC, *2023 State of the Markets, at 42-44 (Mar. 2024)*, https://www.ferc.gov/media/2023-state-markets-report; FERC, *2022 State of the Markets, at 27-29 (Mar. 2023)*, https://www.ferc.gov/media/report-2022-state-market.

*While today's load growth can tempt a crisis-response mindset focused solely on short-term fixes to achieve Speed to Power, it must be balanced with contemporaneous proactive, holistic long-term planning to deliver the highest quality reliability and lowest costs to customers in the long-term.*

It captures economies of scale that 'just-in-time' projects miss and enables high-capacity upgrades to come online ahead of demand. By shifting from short-term, crisis-mode additions to comprehensive, multi-value long-term plans, planners can maintain reliability and affordability while building the transmission capacity required for sustained load growth.[11]

### Order No. 1920 requires long-term regional planning best practices to be adopted

FERC issued its final rule, Order No. 1920,[12] on long-term regional transmission planning in May 2024 and, in November 2024 and April 2025, modified the requirements through Order Nos. 1920-A and 1920-B, respectively.[13] Order No. 1920 adopts many best practices identified in ACEG's initial Report Card and requires transmission providers to participate in a planning process that is "sufficiently long term, forward-looking, and comprehensive" to identify long-term transmission needs.[14]

The rule also requires several common-sense best practices. Regions must produce a 20-year regional transmission plan at least once every five years.[15] Plans must use the best available data to develop at least three scenarios that reasonably capture future outcomes, include an extreme-weather sensitivity, and incorporate seven inputs, including:

1. federal, federally recognized Tribal, state, and local laws and regulations affecting the resource mix and demand;
2. federal, federally recognized Tribal, state, and local laws and regulations on decarbonization and electrification;

11 Chang, J., et al., "It's all one system: Integrate transmission and interconnection planning to support load growth," Utility Dive (Sep. 2025), https://www.utilitydive.com/news/its-all-one-system-integrate-transmission-and-interconnection-planning-Judy-Chang/761240/.

12 Order No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 187 FERC ¶ 61,068 (May 13, 2024) ("Order No. 1920").

13 Throughout the report, we refer to all three orders collectively as "Order No. 1920." Order No. 1920-A, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 189 FERC ¶ 61,126 (November 21, 2024) ("Order No. 1920-A"); Order No. 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 191 FERC ¶ 61,026 (April 11, 2025) ("Order No. 1920-B").

14 Order No. 1920 at P 224.

15 Order No. 1920-A at P 237.

3. state-approved integrated resource plans and expected supply obligations for load-serving entities;
4. trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;
5. resource retirements;
6. generator interconnection requests and withdrawals; and
7. utility commitments and federal, federally recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[16]

Factors 4-7 can be discounted by planners, giving regions flexibility in scenario development that best meets their individual needs.[17] Order No. 1920-A required that planners seek input from states on the categories and allowed states to request additional scenarios.[18]

Once the scenarios are developed, planners must evaluate seven distinct benefits to help identify regional transmission portfolios that will efficiently and cost-effectively address long-term reliability and economic transmission needs. These benefits are:

1. avoided or deferred reliability transmission facilities and aging infrastructure replacement;
2. a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;
3. production cost savings;
4. reduced transmission energy losses;
5. reduced congestion due to transmission outages;
6. mitigation of extreme weather events and unexpected system conditions; and
7. capacity cost benefits from reduced peak energy losses.[19]

As part of solutions development and benefits evaluation, planners may take a portfolio approach and must consider right-sizing options and Advanced Transmission Technologies (ATTs) including Dynamic Line Ratings, Advanced Power-Flow Controls, Transmission Switching (or Transmission Topology Optimization), and High Performance Conductors alongside traditional solutions.[20]

16 *Id. at P 248, 409.*
17 Order No. 1920 at P 507, 528, 865.
18 Order No. 1920-A at 344-345.
19 Id. at P 271-277 and 296-313; Order No. 1920 at P 565 & 597.
20 Order No. 1920 at P 8, 1198-1216, 1239-1247; Order No. 1920-A at 598-600.

Orders No. 1920 and 1920-A also require transmission providers to develop a cost allocation methodology for any selected facilities.[21] States may propose their own cost allocation methodology during compliance and can choose whether or not to use it each planning cycle.[22] The rule further adopts transparency requirements for local transmission planning, including three stakeholder meetings that cover assumptions, needs, and solutions for each planned local facility.[23]

Lastly, Order No. 1920-B largely upheld Order Nos. 1920 and 1920-A clarifying that transmission providers are not required to plan for the long-term needs of unenrolled non-jurisdictional providers (though voluntary agreements are allowed), reaffirming requirements that transmission providers must file any Relevant State Entities cost allocation methods and consult with those entities before amending cost allocation. The order also declined to broaden the definition of Relevant State Entities.[24]

Order No. 1920 requires many of the transmission planning practices evaluated in our initial Report Card. However, delays in compliance threaten to slow or even derail progress. Every region in the country has received extensions on its compliance deadlines (*see Fig. 4*), which means that in many regions, facilities or portfolios may not be approved under the Order No. 1920 process until well after 2030.

Nonetheless, regions do not have to wait for formal compliance to begin implementing regional transmission planning best practices set forth in the rule, and indeed, many have begun implementation, such as MISO through its Long-Range Transmission Planning (LRTP) Tranches.

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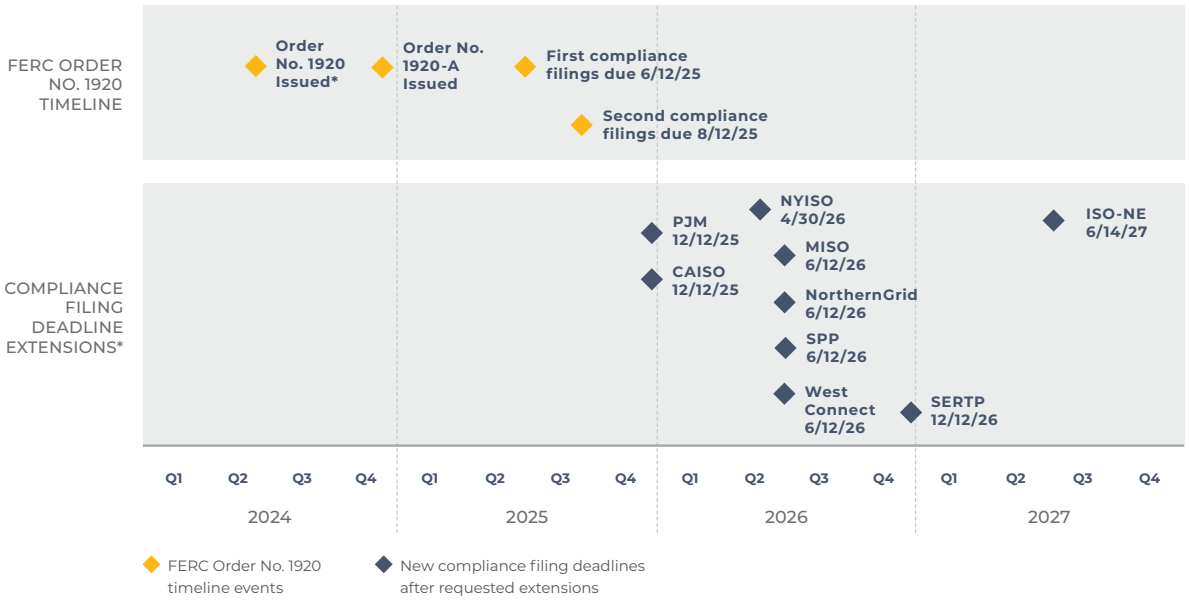
21 Order No. 1920 Section VI "Regional Transmission Cost Allocation"; Order No. 1920-A at 70, 610-793.

22 Order No. 1920-A at P 635-708.

23 Id. at P 804-862.

24 Order No. 1920-B at 21-22 and 152-154.

**FIGURE 4** FERC Order No. 1920 regional compliance filing schedule[25]




** FERC Order No. 1920 requires transmission providers to submit two compliance filings. The lower portion of this chart shows deadline extensions granted for the first compliance filing, which encompasses all of Order No. 1920's requirements except for those related to interregional transmission coordination.*

*SOURCE: FERC, Order No. 1920 Compliance Filings Schedule (Jun. 2025), https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule.*

## Interregional transmission is an added focus this Report Card

Just as students advance to new subjects, this third edition of the Transmission Planning and Development Report Card adds a stronger emphasis on interregional transmission. In the first Report Card, we briefly reviewed interregional planning but focused largely on regional planning and development outcomes.[26] Given the requirements that FERC set out in Order No. 1920, many regions will likely eventually adopt and use the proactive, holistic long-term practices we evaluate here. By contrast, there is no analogous set of planning requirements or standardized benefits for interregional transmission, so a substantial portion of this Report Card's grade now evaluates interregional planning.

25 FERC Order No. 1920 requires transmission providers to submit two compliance filings. The lower portion of this chart shows deadline extensions granted for the first compliance filing, which encompasses all of Order No. 1920's requirements except for those related to interregional transmission coordination. Note that PJM is submitting a two part compliance filing, with the cost allocation portion due June 2026. *See FERC, "Order No. 1920 Compliance Filings Schedule" (Dec. 2025),* https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule; *See also ACEG, "FERC Order No. 1920 Resources," accessed Jan. 2026,* https://cleanenergygrid.org/policies/ferc-order-no-1920-resources/.

26 2023 Report Card at 19-20.

The need for new interregional capacity is significant. As directed by Congress, the North American Electric Reliability Corporation (NERC) conducted the 2024 Interregional Transfer Capability Study (ITCS), focusing exclusively on reliability, and not economic benefits.[27] Even with that narrow scope, NERC recommended 35 GW of additional interregional transfer capability as prudent to maintain reliability.[28]

Interregional transmission offers some of the highest benefit-cost ratios for consumers. A June 2025 ACEG analysis found that interregional lines can deliver $5 in benefits for every dollar invested.[29] This value is particularly high during stress events. Interregional transmission acts as an insurance policy during extreme weather, mitigating price spikes and enabling power imports from neighboring regions with surplus capacity. In its study of transmission path congestion value (*see Fig. 5*) the Lawrence Berkeley National Laboratory has found that roughly half of a transmission path's value accrues in just 10% of the hours each year.[30] Studies also show that even when one region faces peak demand, neighboring regions often have excess resources. Interregional transmission allows operators to access that capacity, reducing the need for redundant generation and lowering overall system costs.[31]

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27 North American Reliability Corporation (NERC), *Interregional Transfer Capability Study (ITCS), v-xvi* (Nov. 2024), https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf ("NERC ITCS").

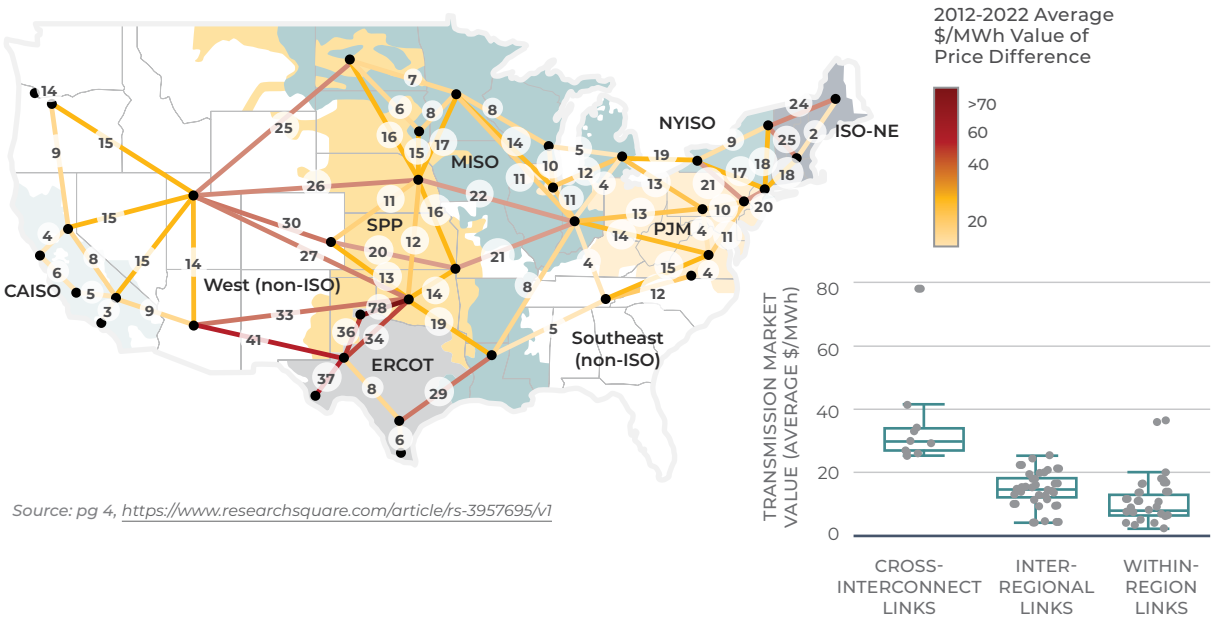
28 *Id.*

29 Transmission saves consumers money at 4.

30 Millstein, D., et al., "The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade" (Feb. 2023) https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.

31 See Brooks, A., et al., *Resource adequacy value of interregional transmission*, Grid Strategies (Jun. 2025) https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf.

**FIGURE 5** Average market value of interregional transmission (2012-2022)[32]




*Source: pg 4, https://www.researchsquare.com/article/rs-3957695/v1*

Despite the well-documented value of interregional transmission planning, regions are planning very little interregional transmission. Current rules and planning structures often require a potential interregional line to be identified as needed and approved in both regions and then approved again through a joint evaluation process. This makes projects difficult to advance, particularly when regions' modeling assumptions, identified needs, benefit calculations, and cost-allocation approaches do not align. In addition, FERC's efforts to encourage interregional planning are limited, and there is no formal requirement for regions to conduct proactive, multi-value interregional planning.[33]

32 Julie Kemp, Dev Millstein, Will Gorman et al. *Electric transmission value and its drivers in United States power markets, 29 March 2024, PRE-PRINT (Version 1),* https://doi.org/10.21203/rs.3.rs-3957695/v1.

33 For additional discussion of the value and barriers to interregional transmission see Pfeifenberger, J., "The Value of Interregional Transmission: Grid Planning for the 21st Century" (Sep. 2023), https://www.brattle.com/wp-content/uploads/2023/09/The-Value-of-Interregional-Transmission-Grid-Planning-for-the-21st-Century.pdf; See also NARUC and Energy and Environmental Economics, *Collaborative Enhancements to Unlock Interregional Transmission* (Jun. 2024), https://pubs.naruc.org/pub/BACDBB9D-02BF-0090-0109-B51B36B74439.

# Results and Discussion

The third edition of the Transmission Planning and Development Report Card combines grades across 1) regional transmission planning and development, 2) interregional transmission planning and development, 3) engagement, and 4) outcomes. This final component quantitatively evaluates transmission constructed, regional and interregional transmission planned, and economic congestion in each region. The sections below provide further discussion on each of the four grade components.

In general, the latest edition of this Report Card saw marginal to significant improvements in grades for many regions. These improvements can be attributed to several factors: recent planning reforms being enacted in light of the issuance of Order No. 1920, a reasonable ad hoc baseline for interregional planning, and overall increase in planned transmission lines due in part to increasing load forecasts. The added emphasis on interregional transmission resulted in different overall grades compared to the first Report Card edition, including a reduction in some regions' grades where strong regional planning is inhibited by little to no interregional planning.

As with the 2023 Report Card, this report grades regions, not specific entities such as RTOs or Order No. 1000 planning authorities, because responsibility for performance extends beyond planning entities to utilities, states, and other stakeholders. This approach extends credits for transmission-related actions, with regional impacts, even when they were not initiated by regional planning entities or advanced through formal regional planning processes. In some cases, often in the non-organized market regions, actions are taken by an individual state or utility outside of regional processes and still have regional significance. In general, most of those actions are captured in the outcomes section. Figs. 6 and 7 summarize the overall grade for each region.

**FIGURE 6** Summary of overall grades by region

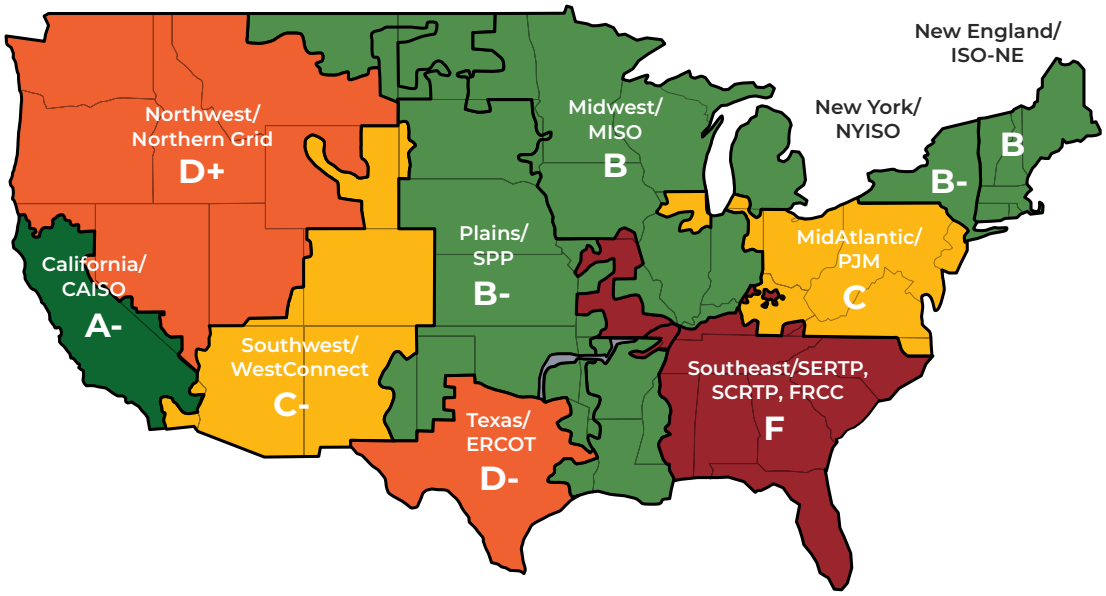



**FIGURE 7** Summary of individual grade components for each region

| REGION | REGIONAL PLANNING | INTERREGIONAL PLANNING | ENGAGEMENT | OUTCOMES | OVERALL GRADE | | 2023 GRADE |
|---|---|---|---|---|---|---|---|
| California | A+ | B- | A- | A | A- | ↑ | B |
| Northwest | F | C | F | B+ | D+ | ↑ | D |
| Southwest | D+ | C | F | B- | C- | ↑ | D- |
| Texas | C | F | B | C- | D- | ↓ | D+ |
| Plains | A | C | B | B- | B- | ↑ | C+ |
| Midwest | A | B- | B+ | C | B | ↔ | B |
| Southeast | F | F | F | F | F | ↔ | F |
| Mid-Atlantic | B | D+ | B | C- | C | ↑ | D+ |
| New York | B+ | C+ | A- | C- | B- | ↑ | C+ |
| New England | B | C | A- | A | B | ↑ | D+ |

## 1. Regional Transmission

The first grade component is regional planning and development. This component — and the metrics associated with it — remain largely unchanged from the 2023 Report Card. This component is based on best planning practices, including 1) proactive generation and load forecasts, 2) scenario-based planning, 3) portfolio-based planning, 4) multi-value evaluation of transmission solutions, 5) inclusion of alternative transmission technologies or business models (like merchant transmission developers), and 6) transmission planning that is integrated with other planning paradigms. This component makes up 35% of the final grade.

Grades for regional planning have risen marginally across most regions as many have continued to make incremental improvements to their planning. In some cases — notably the **Plains, Mid-Atlantic**, and **New England** — grades have improved drastically as these regions have finalized new long-term planning processes, driven in part by the FERC proceedings leading up to the issuance of Order No. 1920. Many of the specific regional transmission planning and development details are explored in the first edition of this Report Card. Below we highlight significant regional updates that have occurred since the Report Card was first published in June 2023.

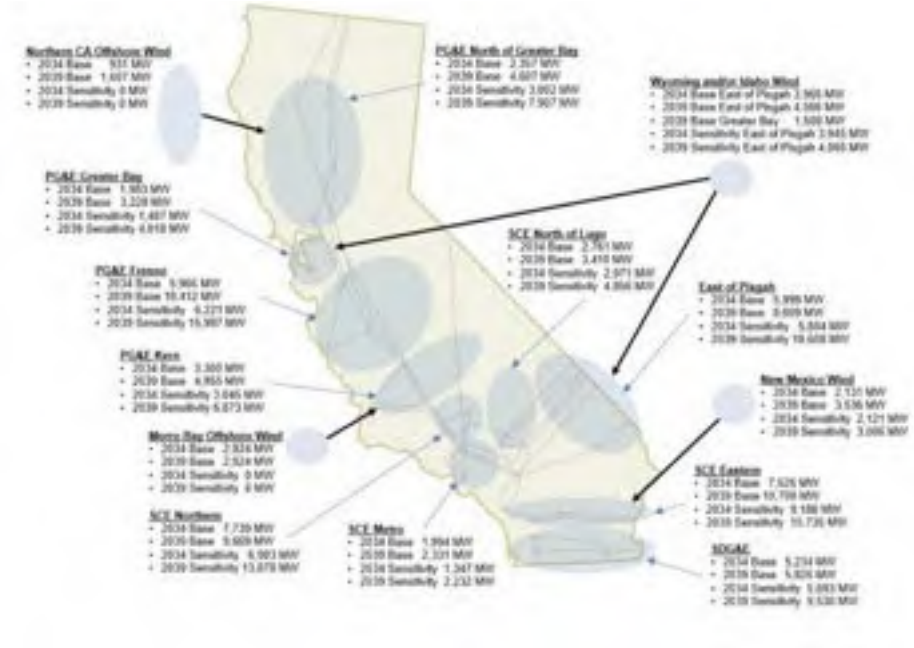
### California

California has received an A+ and has continued to make incremental improvements, with the state once again taking home the highest grade for regional planning. The California Independent System Operator (CAISO) has largely the same proactive, multi-value, scenario-based regional transmission planning process as two years ago and has contin-

ued to make small improvements to the process.[34]

The 2024-2025 Transmissions Plan is the third plan to be adopted after the memorandum of understanding was signed between the California Public Utilities Commission, the California Energy Commission, and CAISO, which tightened the coordination between power and transmission planning, interconnection queuing and resource procurement.[35] The 2024-2025 plan identified 31 new reliability-driven and policy-driven transmission projects[36] totaling $4.8 billion to help accommodate 76 GW of new capacity needed by 2039 to meet policy goals and address load growth, including building, transportation, and other electrification as well as data center growth.[37] CAISO estimates the cost of this portfolio over the lifetime of the projects is approximately 0.5 cents per kWh.[38] The transmission plan is shown in Fig. 8.

**FIGURE 8** CAISO's 2024-2025 Transmission plan




34 For a detailed assessment of CAISO's planning methods see 2023 Report Card at 27-29; *See also 2024 Interim Update at 12-17.*

35 *See* "Memorandum of Understanding Between The California Public Utilities Commission (CPUC) And The California Energy Commission (CEC) And The California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation" (Dec. 2022), https://www.caiso. com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf ("CPUC, CEC, and CAISO Planning MOU").

36 As discussed in the 2023 Report Card, because CAISO's reliability, policy, and economic planning happen sequentially and transmission optimization largely happens in coordination with the resource buildout in the CPUC's capacity expansion modeling, no economic projects were selected again with this plan. CAISO did identify opportunities for economic projects to relieve congestion but none of the projects showed sufficient economic justification to be included in the ISO's final plan. *See 2023 Report Card at 27-29; See also CAISO, 2024-2025 Transmission Plan, at 28-29, 133-151 (May 2025),* https://www.caiso.com/documents/iso-board-approved-2024-2025-transmission-plan.pdf ("CAISO 2024-2025 Transmission Plan").

37 CAISO 2024-2025 Transmission Plan, at 5-13.

38 *Id.* at 9.

Some additional incremental improvements have come from the increased consideration of ATTs, though planned deployments are still limited. The 2023-2024 Transmission Plan contained a limited, case-by-case analysis incorporating a few ATTs. While the 2024-2025 Transmissions Plan appeared to use a similar case-by-base process, it did identify a broader range of projects. CAISO has the opportunity in the 2025-2026 Transmission Plan, currently underway, to further expand on the use of ATTs in planning because of California bill S.B. 1006, which requires California utilities to provide feasibility studies on cost effective deployments of ATTs on their system in January 2026.[39]

CAISO and PJM (discussed later) were the first two regions to file their Order No. 1920 compliance tariffs. Order No. 1920 has a similar requirement to SB 1006 in evaluating potentially beneficial ATT deployments and traditional upgrades alike.[40] CAISO's Order No. 1920 filing extends the region's 10- and 15-year planning horizon to 20-years, making CAISO's 20-year plan no longer information-only, and transitions its annual transmission planning process to a biennial one to better align timelines.[41]

**Northwest**

The Northwest received an F for regional planning. The regional planner in the northwest, NorthernGrid, completed its biannual Order No. 1000 regional transmission planning cycle in 2025 as outlined in Attachment K of the Enrolled Parties tariffs. However, its planning practices remain largely unchanged from our initial 2023 Report Card.[42]

In the Attachment K Tariff of its Enrolled Parties, it notes that NorthernGrid's regional plans are not intended to be a construction plan and NorthernGrid does not have the authority to issue construction orders. NorthernGrid's 2024-2025 Regional Transmission plan did not select any lines for regional cost allocation, and consequently the overall planning process remains largely a compilation of the member utilities' local transmission plans.[43] Alongside its biannual transmission planning process, NorthernGrid conducts information-only economic studies at the request of interested parties. Recent planning cycles have included the evaluation of offshore wind in Oregon,[44] pumped storage hydro proj-

39 Id. at 28-29, 195-196; See also CAISO, *2023-2024 Transmission Plan*, 24-27 (May 2024) https://www.caiso.com/documents/iso-board-approved-2023-2024-transmission-plan.pdf; Senator Padilla, California State Senate, S.B. 1006, February 2024, https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_ id=202320240SB1006.

40 CAISO, Tariff Amendment - Order No. 1920 Compliance Filing, FERC Docket ER26-704, December 2025, https://www.caiso.com/documents/dec-9-2025-tariff-amendment-order-no-1920-compliance-filing-er26-704.pdf.

41 *Id.* at 19-20.

42 For a detailed assessment of the Northwest's planning methods see 2023 Report Card at 39-40; *See also 2024 Interim Update at 57-59.*

43 *See* NorthernGrid, *Regional Transmission Plan for the 2024-2025 Northern Grid Planning Cycle* (Nov. 2025), https://www.northerngrid.net/private-media/documents/2024-2025_NorthernGrid_RTP.pdf.

44 *See* NorthernGrid, *Economic Study Request Offshore Wind in Oregon* (Jul. 2023), https://www.northerngrid.net/private-media/documents/2022_ESR_OSW_Approved.pdf.

ects in Wyoming and Oregon,[45] an additional pumped storage hydro project in Oregon,[46] and potential congestion impacts of the high-capacity North Plains Connector transmission facility.[47]

The biggest update to planning in the Northwest is potential reforms to Bonneville Power Administration's (BPA) transmission planning. Since 2023, BPA has announced new transmission investments — $5 billion to connect more than 20 GW of new resources in its last few Transmission Service Request planning cycles.[48] This renewed focus on transmission development is primarily due to increased demand for transmission service from new generation and anticipated load growth in the Pacific Northwest over the next decade.[49] Because of the significant increase in requests for transmission service, BPA paused its transmission planning at the beginning of 2025, and then over the summer of 2025 announced it would be undertaking significant reforms to its existing planning processes, called the Grid Access Transformation Project.[50] Under this new process, BPA proposed a six-point solution framework divided between near-term actions to clear bottlenecks and stabilize planning in order to transition to its "Future State" of planning with the stated goal of implementing long-term reforms to enable proactive, scenario-driven transmission planning and execution of service within a 5-6 year delivery window.[51]

As seen in Fig. 9, BPA is currently working on the near term transitional reforms under the TC-27 Tariff proceeding.[52] BPA held its first workshop in December 2025 where it discussed its goal of establishing a commercial expansion delivery pipeline that enables BPA to provide service in 5–6 years or less on a consistent basis and across customer types.[53] While BPA's efforts are much needed, it is still critical that BPA coordinate with other transmission owners on regional planning. This process is still in its early stages but

45 *See* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Wyoming* (Jul. 2023), https://www.northerngrid.net/private-media/documents/2022_ESR_PSH_Approved.pdf.

46 *See* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Oregon* (Apr. 2024), https://www.northerngrid.net/private-media/documents/ESR_OSW_PSH_Final.pdf.

47 *See* NorthernGrid, *Economic Study Request: North Plains Connector* (Jan. 2025), https://www.northerngrid.net/private-media/documents/ESR_NorthPlains_Approved_REport.pdf.

48 Bonneville Power Administration (BPA), "TSR Study and Expansion Process (TSEP) 2022 Cluster Study Results," December 15, 2022, at 6-7, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2022-cluster-study-results-overview-customer.pdf; BPA, "TSR Study & Expansion Process (TSEP) Update Summary of the 2023 Cluster Study," February 29, 2024, at 24-27, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/02-29-24-2023-cs-findings-summary-part1-external.pdf.

49 PNUCC, *Northwest Regional Forecast of Power Loads and Resources*, at 5 (Apr. 2025), https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf; *See also* BPA, *2025 Pacific Northwest Loads and Resources Study*, at 21 (May 2025), https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.

50 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project ("GAT Project").

51 *See* BPA, "Grid Access Transformation Workshops" (Jul. 2025), https://www.bpa.gov/-/media/Aep/transmission/Grid-Access-Transformation/Jul-10-TPR-Wrkshp-Presentation.pdf.

52 BPA, "TC-27 Tariff Proceeding," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/tc-27-tariff-proceeding.

53 BPA, "Grid Access Transformation Future State Workshop Accelerate Expansion Program" (Dec. 2025) https://www.bpa.gov/-/media/Aep/transmission/Grid-Access-Transformation/12-17-25-GAT-Future-State-Workshop.pdf.

depending on the outcome and coordination with entities in the region, BPA's proactive planning reforms developed for its Future State may help improve the Northwest's regional grade in future Report Cards.

In the Northwest, independent/merchant transmission developers and individual transmission owners are planning and developing significant transmission projects outside of the regional planning processes, but that will have regional impacts. Northwestern transmission owners and stakeholders, though not NorthernGrid itself, are also participating in the west-wide WestTEC transmission planning study. Credit is given and discussion of independent/merchant projects is in the outcomes section and discussion of the WestTEC process is in the interregional planning section below.

**FIGURE 9** BPA's proposed Six-Point Solution Framework[54]

### Southwest

The Southwest received a D+ for regional planning. The Southwestern transmission planning organization, WestConnect, completed its biannual regional transmission planning cycles in 2025. Like their northern neighbor, their planning practices remain largely unchanged from our initial 2023 Report Card.[55]

As noted in the NorthernGrid section above, transmission owners and stakeholders, though not WestConnect itself, are participating in WestTEC. For the Southwest region, this study represents a potentially meaningful supplement to existing regional planning. We discuss the broader west-wide value of WestTEC further below in the interregional planning section.

54 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project.

55 For a detailed assessment of the Southwest's planning methods see 2023 Report Card at 45-47; *See also 2024 Interim Update at 59-61.*

The WestConnect 2024-2025 Regional Transmission Study Plan did not identify any regional needs.[56] As discussed in the interim update in 2024, the 2024-2025 Regional Transmission Study Plan did include three new scenarios in its planning, including a decreased facility rating scenario, extreme cold weather scenario, and 20-year increased renewable scenario.[57] The scenarios were for informational purposes only, and the 20-year increased renewable scenario was not completed due to a decision to stop all non-Order No. 1000-mandated activities in early 2025.[58]

The request to stop work came from the remaining WestConnect Enrolled Transmission Owners (ETOs) after FERC ordered the WestConnect ETOs to revise their Open Access Transmission Tariffs (OATTs) to exclude non-jurisdictional "coordinating transmission owners" so that its regional transmission planning process will only identify and plan for the regional transmission needs of enrolled transmission providers (who are FERC-jurisdictional).[59] This effectively removed nine transmission owner members from the WestConnect footprint and caused a mid-cycle reevaluation of study plan activities. Had the scenario-based planning continued, a higher score may have been awarded. We discuss additional impacts of these governance changes at length in the engagement section below.

In the Southwest, much of the transmission planning occurs through states, utilities, or by independent/merchant transmission developers. Interwest Energy Alliance released a two-part report in 2025 on opportunities to evaluate transmission in Integrated Resource Plans (IRPs). The first report details five common methods for evaluating transmission constraints in IRPs and then discusses the range of practices utilities have used and the benefits or drawbacks.[60] The second report evaluates five recent IRPs for Interior West utilities based on how well transmission is incorporated across the five methods, finding that PacifiCorp and the Public Service Company of New Mexico (PNM) ranked the two highest in terms of their approach to evaluating transmission expansion in their IRPs relative to the other utilities evaluated.[61] The report also includes utility-specific recommendations for better evaluation of transmission expansion in IRPs.[62] As an example, in

56 WestConnect, *Regional Transmission Plan Report: WestConnect 2024-25 Regional Transmission Planning Cycle*, 6 (Dec. 2025), https://doc.westconnect.com/Documents.aspx?NID=21545&dl=1 ("WestConnect 2024-25 Transmission Plan") .

57 *Id.* at 7.

58 *Id.* at 56-64.

59 WestConnect Enrolled Transmission Owners, "Letter to WestConnect on Non-Tariff Activities for the Remainder of 2025" (Jun. 2025), https://doc.westconnect.com/Documents.aspx?NID=21407&dl=1; *See also Order on Remand, 189 FERC ¶ 61,028 at P 19 (2024) & Order Accepting Tariff Revisions and Terminating Section 206 Proceedings, 191 FERC ¶ 61,074 (2025).*

60 *See* Franklin, R. & Fitch-Fleischmann, B., *Evaluating Transmission Opportunities in Integrated Resource Plans Part 1: How to Incorporate Transmission in IRP Models* (Sep. 2025), https://interwest.org/wp-content/uploads/2025/09/Transmission-in-IRP-Part-1.pdf.

61 *See* Franklin, R. & Fitch-Fleischmann, B., *Evaluating Transmission Opportunities in Integrated Resource Plans Part 2: A Review of Interior West Utilities* (Sep. 2025), https://interwest.org/wp-content/uploads/2025/10/Transmission-in-IRP-Part-2.pdf.

62 *Id.* at 35-40.

2025 PNM completed its 20-Year Transmission Outlook where they evaluated numerous conceptual projects to meet carbon-free goals. The study concluded that further work was needed including additional scenarios and evaluation of economic benefits for the conceptual projects.[63] We also discuss in further detail transmission planning and development by the Colorado Electric Transmission Authority, the New Mexico Renewable Energy Transmission Authority and Xcel Energy in the outcomes section.

### Texas

Texas received a C for regional planning. In response to House Bill 5066 from the 88th Texas Legislature, the Electric Reliability Council of Texas (ERCOT) developed the Permian Basin Reliability plan to maintain reliability and connect significant new loads in the Permian Basin in west Texas, primarily from new oil and gas and data center loads, as well as address load growth in eastern Texas.[64] The plan was released in July 2024 and identified two options, a 345 kV portfolio and 765 kV portfolio.[65] The Public Utility Commission of Texas (PUCT) approved the plan in October 2024 but delayed a decision on which portfolio to use until April 2025 when it selected the 765 kV transmission plan.[66] Alongside the Permian Basin Reliability Plan, ERCOT released its 2024 annual Regional Transmission Plan (RTP), which included for the first time two transmission plans, a 345 kV portfolio and 765 kV portfolio, called the Strategic Transmission Expansion Plan (STEP).[67] After review by stakeholders, ERCOT's board approved the planned 765 kV projects, which create an eastern Texas 765 kV loop closer to load centers and connect the western ends of the three 765 kV Permian Basin Reliability plan projects (*see Fig. 10)*.[68]

63 *See* Public Service Company of New Mexico, *PNM 20-Year Transmission Outlook* (Sep. 2025), https://www.pnm.com/documents/d/pnm.com/pnm_20-year-transmission-outlook_92025.

64 Electric Reliability Council of Texas (ERCOT), *Permian Basin Reliability Plan Study, July 2024*, at ii-xi, https://interchange.puc.texas.gov/Documents/55718_17_1414013.PDF ("Permian Basin Reliability Plan").

65 *Id.*

66 *See* Public Utility Commission of Texas, "Second Order Approving the Reliability Plan for the Permian Basin Region" (Apr. 2025) https://interchange.puc.texas.gov/Documents/55718_109_1492424.PDF.

67 *See* 2023 Report Card at 48-51 and 2024 Interim Report Card at 50-54 for additional details on ERCOT's transmission planning; *See also* ERCOT, *2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison* (Jan. 2025), https://interchange.puc.texas.gov/Documents/55718_54_1462478.PDF ("ERCOT 2024 RTP").

68 ERCOT, "TOPIC: ERCOT Transmission Planning: 345-kV and TX 765-kV Strategic Transmission Expansion Plan (STEP)" (Dec. 2025), https://www.ercot.com/files/docs/2025/01/28/ERCOT_Trending_Topic_345-kV_vs_765-kV_Transmission.pdf ("ERCOT Trending Topic").

**FIGURE 10** ERCOT's 765 kV Permian Basin Reliability Plan, 765 kV STEP projects, and needed 345 kV New Lines and Upgrades[69]

As a part of the 2024 RTP, ERCOT estimated two years (2034 and 2039) for multiple benefits for each portfolio, including production cost savings, system-wide consumer energy savings, reduction in congestion rent, power loss reduction, and reductions in construction related outage costs.[70] In addition, while the 2024 RTP portfolio is designed to accommodate a total of over 150 GW of load forecasted for summer 2030 — representing an approximately 35% increase over the 2029 load forecast in the 2023 RTP — the economic analysis was conducted using the 2024 Long Term System Assessment scenarios, which only estimated peak demand in 2034 as 107 GW.[71] ERCOT also conducted a load sensitivity analysis where roughly 20 GW of load did not materialize and found that significant portions of both 345 kV or 765 kV plans were still needed.

There is significant evidence that 765 kV lines provide the lowest cost delivery of power to consumers and ERCOT's 765 kV STEP plan highlights many of those benefits (*see Fig. 11*). However, ideally, ERCOT would have used a 20-year, scenario-based plan (beyond sensitivities), that proactively plans for generation additions and retirements. In addition, rather than just two years of benefits ERCOT could have expanded the benefits analysis to cover the lifetime of the projects and used their benefits plus the reliability and economic benefits identified in Order No. 1920.[72]

69 *Id.*

70 ERCOT 2024 RTP at 8-21.

71 *Id.* at 18; ERCOT, "Completion of the 2024 Regional Transmission Plan (RTP)" (Dec. 2024), https://www.ercot.com/services/comm/mkt_notices/M-A122024-01.

72 Siemens also conducted a benefit-cost analysis that found more beneficial results than ERCOT but did not expand on the benefits or use of only two years. *See generally* Siemens, "Cost Benefit Analysis of 765-kV Transmission Facilities in ERCOT" (Apr. 2025), https://interchange.puc.texas.gov/search/documents/?controlNumber=55718&itemNumber=107.

**FIGURE 11** Comparison of annual 765 kV STEP benefits to 345 kV plan[73]

While the amount of transmission Texas has planned and approved in the last two years is significant, ERCOT continues to plan most of its projects in a siloed manner. The 765 kV lines arose through a reliability-only planning process. ERCOT's reliability planning process falls short of best practices, including use of a 10-year time horizon and omission of proactively assessed generation additions or retirements outside of the informational-only Long Term System Assessment. In addition, ERCOT did not include multiple portfolios or any assessment of benefits in the 2025 RTP, despite including it in the 2024 RTP. Despite these drawbacks, credit is given for the work done in its reliability plans to address Texas State mandates around reliability in the Permian Basin and addressing large load growth.

There are some signs of improved planning practices in the coming years. Notably, ERCOT intends to change how generation is added in its reliability modeling to meet load growth starting in 2026.[74] The 2025 RTP economic analysis was also the first use of the new congestion cost savings metric, but only looked at 2027-2030.[75] Ideally, those practices would expand and continue.

### Plains

The Plains region received an A for regional planning, and has continued to improve its regional transmission planning over the last few years, in particular through load and resource forecasting.[76] These changes have resulted in the region now having one of the highest grades. SPP is facing significant load growth, notably from data centers and oil

73 *See* ERCOT Trending Topics.

74 ERCOT, *2025 Regional Transmission Plan*, iii (Dec. 2025), https://www.ercot.com/mp/data-products/data-product-details?id=pg7-048-m (2025 RTP).

75 *See* 2025 RTP Appendix C.

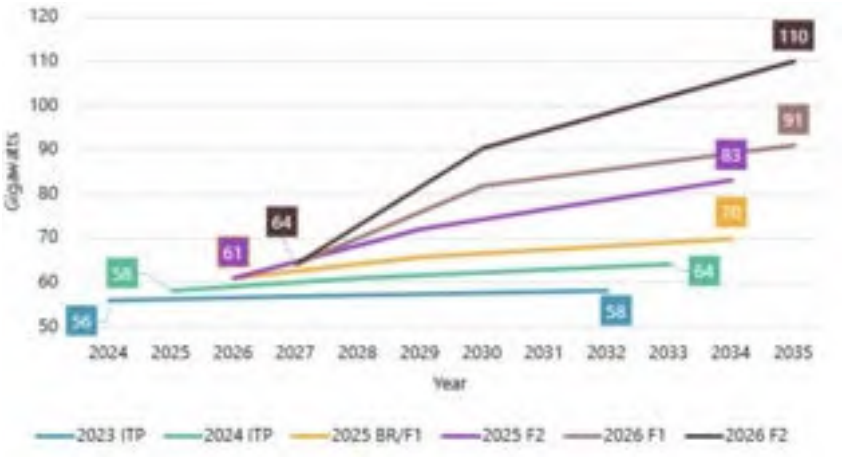
76 For a detailed assessment of SPP's planning methods see 2023 Report Card at 40-42; *See also 2024 Interim Report Card at 38-44.*

and gas developments in New Mexico, Texas, Oklahoma, and North Dakota.[77] This large demand growth helped drive historic investments in their two most recent transmission plans.

SPP's 2024 Integrated Transmission Plan (ITP) includes a historic $7.68 billion investment in transmission with the first 765 kV line planned in the region.[78] The projects are estimated to have a $8.90 to $9.57 in benefits for every dollar invested, resulting in estimated savings on the average retail residential monthly bill of $10.55 to $11.47.[79] The 2024 ITP also included modeling and solution development based on two historic extreme weather events, Winter Storms Uri and Elliot.[80]

As Fig. 12 shows, SPP faced even larger load growth in its 2025 and 2026 planning processes. SPP is forecasting a 35% increase in demand, even under conservative assumptions, and could double in the next 10 years.[81]

**FIGURE 12** SPP Load Growth by Study[82]




To address this demand, SPP approved a historic $8.6 billion investment of fifty transmission facilities for the 2025 ITP. This includes four 765 kV lines approved for construction, comprising almost half of SPP's now planned 765 kV regional "backbone" transmission (*see Fig. 13*).[83] In support of its ITP, SPP notes that using 765 kV lines can deliver up to six times the power of 345 kV lines while requiring nearly five times less land.[84]

77 SPP, *2025 Integrated Transmission Planning Assessment Report*, 15-20, (Nov. 2025), https://www.spp.org/media/2429/2025-itp-report-v10.pdf ("2025 ITP").

78 SPP, *2024 Integrated Transmission Planning Assessment Report*, 1-13 (Jan. 2025), https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf ("2024 ITP").

79 *Id.* at 184-192.

80 *Id.* at 6-7, 50-56.

81 *Id.* at 1-13.

82 *Id.* at 97.

83 *See* SPP, "SPP board advances regional transmission plan to keep pace with accelerating growth and ensure grid reliability" (November 2025), https://www.spp.org/news-list/spp-board-advances-regional-transmission-plan-to-keep-pace-with-accelerating-growth-and-ensure-grid-reliability/.

84 SPP, "Powering the Future: The 2025 Integrated Transmission Plan," (November 2025), https://www.spp.org/documents/75194/2025%20itp%20fact%20sheet%20final.pdf.

While the plan represents a significant investment, the approved plan omits approximately 1,000 miles of 765 kV lines in its southern footprint. Concerns from some stakeholders of high upfront costs, potential cost overruns, and need led SPP to defer the lines for further analysis in the 2026 ITP.[85] These deferrals could impact SPP's transition to the Consolidated Planning Process, discussed in detail below, as the timing of large portfolio approvals could influence the initial Generalized Rates for Interconnection Development Contribution (GRID-C) rate design.

In addition, SPP is creating the Cost Control and Allocation Review and Evaluation Team to "review, evaluate, assess, and recommend refinements or alternatives to the current transmission cost controls and cost allocation methodologies."[86] The team will "emphasize efficiency and increase transparency into cost formation and decision-making" and is expected to provide a final report and recommendation, which will carry significant weight in October 2026.[87]

The 2025 ITP has the highest benefit-to-cost ratio in the region's planning history with the portfolio overall estimated to provide between $12.10 to $17.60 in benefits for every dollar invested, saving ratepayers between $19.42 to $26.09 dollars annually after accounting for the cost of transmission.[88]

As discussed above, the 2024 ITP added extreme weather scenarios, and the 2025 ITP built on that work creating a new resiliency need. The resiliency need has three categories, peak Locational Marginal Price, transfer capacity within subregions, and load shed reduction during extreme weather. These categories of resiliency needs allow SPP to develop better transmission solutions to improve overall resilience.[89]

85 2025 ITP at 29-34.

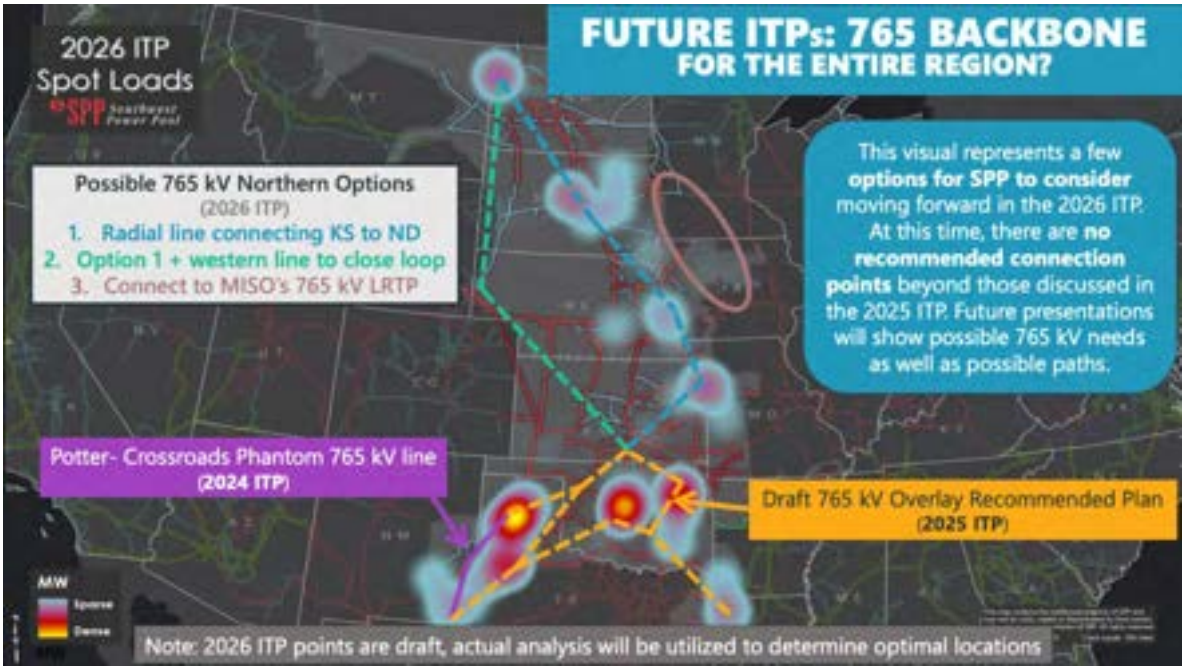
86 SPP, "Cost Control and Allocation Review & Evaluation Team," accessed Jan. 2026, https://spp.org/stakeholder-groups-list/organizational-groups/cost-control-and-allocation-review-evaluation-team/.

87 *See* SPP, "Cost Control and Allocation Review & Evaluation Organizational Group Scope Statement" (Nov. 2025) https://spp.org/Documents/75412/CARE%20Materials%2020251210.zip.

88 2025 ITP at 241-249.

89 *Id.* at 112-119.

**FIGURE 13** Potential 765 kV overlay being discussed in SPP[90]




90 SPP, "Special Joint Stakeholder Briefing" 45 (Sep. 2023), https://www.spp.org/documents/74668/25-09-03%20board%20rsc%20joint%20briefing%20materials%20v3.pdf.

## SPP Takes Historic Step to Fully Integrate Transmission Planning with Generation and Load Interconnection Planning

Since 2020, SPP has been working to create the Consolidated Planning Process (CPP). The CPP arose in response to a recognition of improvements needed across its planning process. The traditional planning approach handles resource, load, and transmission planning as separate processes which created uncertainty, delays, redundancies, and less efficient transmission solutions. The goal of the CPP is to bring together all of SPP's planning process, combining transmission and generator interconnection planning, helping ensure the optimal transmission upgrades are built at the right time and costs are shared based on benefits.[91]

At a high level, CPP merges SPP's long-term regional transmission planning and generator interconnection into a single, streamlined process designed to identify "multi-driver" transmission solutions that serve both load and generation needs. The CPP is designed as a three-year repeating planning cycle that includes a 20-year planning assessment (CPP-20) and subsequent 10-year planning assessments (CPP-10), which incorporate interconnection studies and a regional planning assessment over a 10-year horizon.[92]

One of the key components of the CPP is the GRID-C. The GRID-C is a flat cost ($/MW) all generation interconnection customers will have to pay to interconnect as a part of the 10-year planning. GRID-C is initially developed based on the CPP-20, which includes a future resource and load forecast as well as needed transmission. Once the GRID-C is determined, the cost is assigned to actual generator interconnection customers within the CPP-10 and paid to load. Ideally, GRID-C will be used to fund more holistic transmission solutions in the CPP-10.[93]

SPP filed its CPP Phase 1 tariff revisions in November 2025 and is hoping for the changes to go into effect in March 2026. In the meantime, SPP is continuing to work on the CPP "transition study," which will be completed by the end of 2026 and determine the initial GRID-C rates. SPP will continue to develop legacy ITPs for 2026 and 2027, with the CPP 10-year assessments beginning in 2028.[94]

91 SPP, "CPP Education Session 1," Slide 18 (May 2025), https://www.spp.org/calendar-list/cpp-education-series-session-1-consolidated-planning-process-cpp-overview-net-conference-20250507/ ("CPP Education Session 1").

92 SPP, Submission of Revisions to the SPP Open Access Transmission Tariff to Implement the Consolidated Planning Process, FERC Docket ER26-414, November 2025, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251103-5149&optimized=false&sid=7c8ec448-abb4-495d-b95e-f5d1266d32e4.

93 SPP, Submission of Revisions to the SPP Open Access Transmission Tariff to Implement the Consolidated Planning Process, FERC Docket ER26-414, November 2025, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251103-5149&optimized=false&sid=7c8ec448-abb4-495d-b95e-f5d1266d32e4.

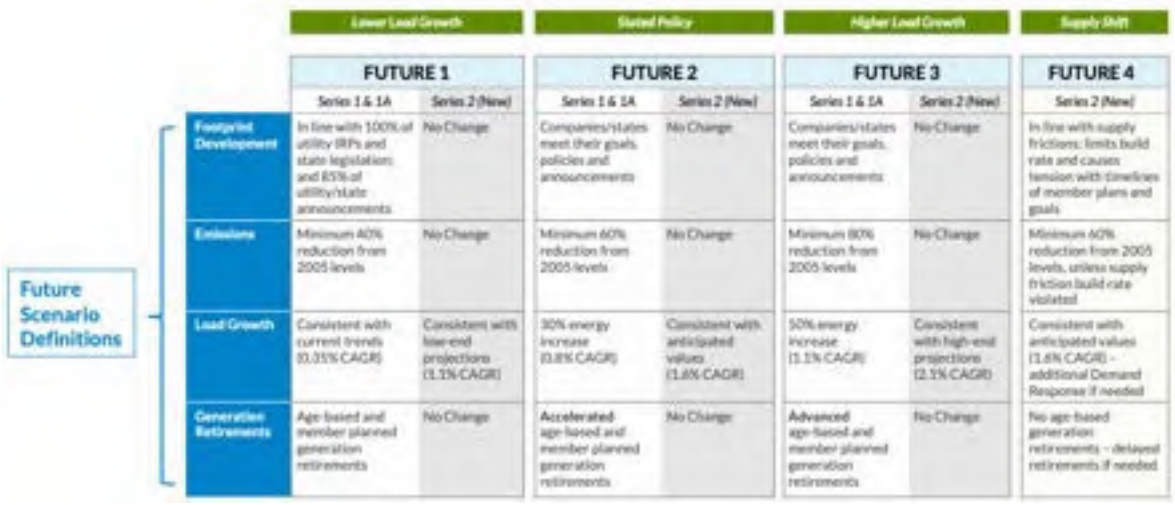
94 CPP Education Session 1 at Slide 36.

### Midwest

The Midwest received an A for regional planning. MISO has largely stuck to the transmission planning described in the 2023 Report Card.[95] In December 2024, MISO approved the LRTP Tranche 2.1 portfolio, a $21.8 billion portfolio of 1,800 miles of 765 kV backbone transmission lines and 1,800 miles of 345 kV lines. The portfolio is estimated to provide between $1.80 to $3.50 in benefits for every $1 invested in the projects.[96]

In 2025, MISO did not develop a new LRTP portfolio; instead, it is refreshing its Futures Scenarios, which are the 20-year load, resource, and policy assumptions that underlie the LRTP planning process. A final report is expected in Q1 of 2026 for the refreshed (Series 2) Futures, with Futures 1-3 largely reflecting the assumptions from the first two rounds of Futures development (Series 1/1A). New to this refresh will be a fourth scenario that is intended to test the impacts of supply chain constraints on new resource additions.[97] Fig. 14 shows the major changes of each future between Series 1/1A and 2.

**FIGURE 14** Summary of assumptions in each of the four Futures MISO is developing for its Series 2 Futures[98]




At the end of 2025, MISO also approved its annual transmission plan, the 2025 MISO Transmission Expansion Plan (MTEP), consisting of 432 projects and representing over a $12 billion investment (*see Fig. 15)*.[99] Similar to the MTEP24, new large loads are a significant driver of many projects, in particular 49 expedited projects totaling more than $4 billion,

95 *See* 2023 Report Card at 31-34 and 2024 Interim Report Card at 22-25 for additional details on the Midwest's transmission planning.

96 MISO, "Long Range Transmission Planning," accessed Jan. 2026, https://www.misoenergy.org/planning/long-range-transmission-planning/.

97 *See* MISO, "Futures Redesign Project Status & Schedule" (Dec. 2025) https://cdn.misoenergy.org/20251217%20Futures%20Workshop%20Items%2001%20%2002%20Presentation732081.pdf.

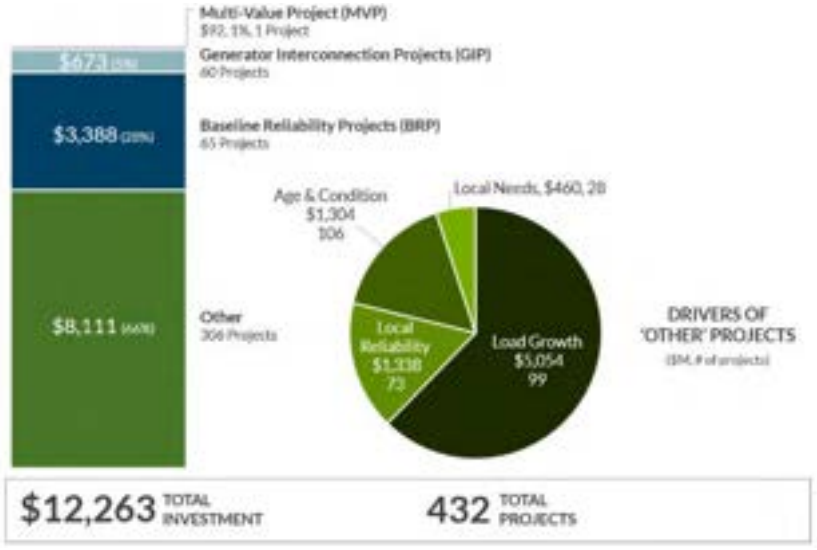
98 *Id.* at 13.

99 MISO, *MTEP25 Transmission Portfolio*, 36 (Dec. 2025), https://cdn.misoenergy.org/MTEP25731615.zip ("MTEP25").

with an estimated 11.6 GW being supported by MTEP25 projects.[100]

In October 2025, FERC also ordered MISO to describe how it will integrate merchant high-voltage direct current (HVDC) transmission projects into its transmission planning.[101] FERC's Order was in response to a complaint by Invenergy, the developer of the HVDC Grain Belt Express project, that MISO's process was unfair and creating duplicative transmission projects by not properly accounting for proposed merchant HVDC lines.[102] As required, MISO revised its tariff to include HVDC and filed it with FERC in January 2026.[103]

**FIGURE 15** MISO's MTEP 25 Investment Summary[104]




As discussed in the previous Report Cards, MISO's grades are impacted by its MISO South region, which includes parts of Arkansas, Mississippi, Louisiana, and Texas and has not participated in any proactive planning practices. To date, MISO South has not had a successful transmission project with regional cost allocation. This lack of proactive planning in MISO South has increasingly become a problem as the utilities have advanced significant investments in new transmission capacity through the local transmission planning process and MISO's reliability and expedited project review processes ("other" projects), largely considered less efficient than regional planning.

For example, Louisiana and southeast Texas comprised $3.9 billion of the $9 billion MTEP23 projects,[105] and in MTEP 24, projects in MISO South made up almost $2 billion

100 *Id.*

101 FERC, Order on Complaint, 193 FERC ¶ 61,033 (Oct. 2025), https://www.ferc.gov/media/e-3-el22-83-000 ("Order on Complaint").

102 Complaint of Invenergy Transmission LLC vs. Midcontinent Independent System Operator, Inc. under EL22-83, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220808-5195&optimized=false.

103 MISO, OATT Tariff Attachment FF revisions, available: https://cdn.misoenergy.org/EL22-83%20-%20Att%20FF%20Compliance%20Revisions%20-%2001-12-2026735542.pdf.

104 MTEP25 at 34.

105 MISO, *MTEP23 Transmission Portfolio*, 25 (Dec. 2023), https://cdn.misoenergy.org/MTEP23650305.zip.

of the $6.7 billion.[106] Louisiana has the most investment of all MISO states in MTEP 25, at more than $3.4 billion in reliability projects and projects needed to meet load growth, with MISO South accounting for $4.7 billion overall.[107] However, the region's grade could see improvement in future Report Cards as MISO is expected to begin its South LRTP planning in 2026. MISO has said it will use the Series 2 Futures for the South LRTP planning but will start with a more limited "South Load Pocket Risk Assessment."[108]

### Southeast

The Southeast received an F for regional planning. For the 2023 Report Card, we reviewed three Order No. 1000 regional planning entities in the Southeast: Southeastern Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC). However, with the issuance of Order No. 1920, SCRTP has announced they will be joining SERTP and retiring the SCRTP Order 1000 process.[109]

SERTP has continued to not select any public policy scenarios for study in both the 2024 and 2025 planning cycle, and no regional projects have ever been selected.[110] SERTP and FRCC continue to essentially "roll up" the local transmission plans from their member utilities and have not made changes to their existing regional transmission planning processes.[111] In addition, SERTP's plan relies on incomplete or inconsistently reported data from the SERTP sponsors.[112] The process continues to lack transparency, stakeholder involvement is often limited, both of which are discussed further in the Engagement section.

Despite these planning realities, there is a clear need for additional transmission capacity in the Southeast. The 2024 NERC ITCS showed a need for transmission to maintain reliability and the Southeast is projecting some of the largest load growth over the next five

106 MISO, *MTEP24 Transmission Portfolio*, 180 (Dec. 2024), https://cdn.misoenergy.org/MTEP24720395.zip.

107 MTEP25 at 36.

108 *See* MISO, "Reliability Imperative: Transmission Evolution" (Sep. 2025), https://cdn.misoenergy.org/20250916%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution717558.pdf.

109 South Carolina Regional Transmission Planning, "Home," accessed Jan. 2026, https://www.scrtp.com/.

110 *See* SERTP, *Regional Transmission Plan & Input Assumptions Overview* (Nov. 2024), https://www.southeasternrtp.com/docs/general/2024/2024_Regional_Transmission_Plan_and_Input_Assumptions.pdf; *See also* SERTP, *Regional Transmission Plan & Input Assumptions Overview* (Nov. 2025), https://www.southeasternrtp.com/docs/general/2025/2025%20Regional%20Transmission%20Plan%20and%20Input%20Assumptions.pdf.

111 *See* 2023 Report Card at 42-45 and 2024 Interim Report Card at 45-49 for additional details on the Southeast's transmission planning.

112 In a 2025 report The Brattle Group found that Southeast "utilities have identified the need for over 80 GW of new power generation, but the regional plan only accounts for 12% of that growth. This mismatch could lead to a system that is ill-prepared for the coming changes and result in bottlenecks on the grid and delays in bringing new power online." Haggerty, J.M., *Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy*, The Brattle Group, 8 (Apr. 2025), https://carolinasceba.com/wp-content/uploads/2025/04/SERTP-Report-Summary_FINAL.pdf.

years.[113]

However, as in the Northwest and Southwest, this need for transmission is showing up in the Southeast at the state level and in individual Transmission Owner transmission plans. The Georgia utilities' ten-year transmission planning process currently has almost 500 miles of new 500 kV transmission lines planned to go in-service by 2033. These lines are being developed to bring in new resources to accommodate load growth and maintain reliability.[114]

In the Carolinas, Duke Energy has almost completed its first round of Multi-Value Strategic Transmission planning. This process is an attempt to create a more proactive, multi-value local transmission plan.[115] The process has good participation from interested parties and does include some improvements, including scenario-based planning based on Duke's recent IRP and stakeholder input along with production cost modeling to quantify benefits for proposed projects.[116] However, there are concerns that may prevent Duke from achieving its stated goals. The first Multi-Value Strategic Transmission study cycle used a 10-year planning horizon, which will likely prevent longer lead time projects from being identified and built, and the study did not include economic drivers for transmission needs.[117] The study has not yet been finalized, but draft results suggest a more narrow focus, which may have removed high-capacity solutions from consideration, even though higher-capacity solutions can provide larger economies of scale.[118]

Looking to the future, compliance with FERC Order No. 1920 should improve the Southeast's grade for regional transmission planning. That said, the SERTP sponsors have pushed their Order No. 1920 compliance filing to December 2026, meaning the first projects selected under Order No. 1920 planning process, if any, will not be until 2031. This date is too late to accommodate the exponential near-term load growth the SERTP sponsors are expecting.[119]

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113 *See* NERC, *Interregional Transfer Capability Study (ITCS): Strengthening Reliability Through the Energy Transformation*, xvi (Nov. 2024), https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf; Grid Strategies 2025 Load Growth Report at 22.

114 Georgia Power, *2025 Integrated Resource Plan*, 120 (Jan. 2025), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf.

115 *See* Carolinas Transmission Planning Collaborative (CTPC), "Multi-Value Strategic Transmission Planning" (Apr. 2024), https://carolinastpc.org/static/ctpc/Multi-Value-Strategic-Transmission-Planning-Process.pdf.

116 *See* CTPC, "2024 Multi-Value Strategic Transmission (MVST) Study," August 16, 2024, https://carolinastpc.org/media/reference/2024/08/19/2024_CTPC_MVST_Study_Scope_08_16_2024_Clean.pd.

117 *See* Carolinas Transmission Planning Collaborative (CTPC), "2024 Multi-Value Strategic Transmission (MVST) Study" (Aug. 2024), https://carolinastpc.org/media/reference/2024/08/19/2024_CTPC_MVST_Study_Scope_08_16_2024_Clean.pdf; *See* "Joint Comments on MVST Study Proposals," (Aug. 2024), https://carolinastpc.org/media/reference/2024/09/24/Aug_26_2024__Joint_Comments_on_MVST_Scenarios.pdf.

118 *See* SELC, NCSEA, SACE, and Sierra Club, "Comments on Preliminary MVST Solutions and Proposed Alternatives" (Sep. 2025), https://carolinastpc.org/media/reference/2025/09/18/SELC_NCSEA_SACE_Sierra_Club_Solutions_Comments_9.15.25.pdf.

119 Notice of Extension of Time, FERC Docket No. RM21-17 (Oct. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251017-3019&optimized=false&sid=025f19da-8026-45b8-b93b-b8e01ef260b3.

### Mid-Atlantic

The Mid-Atlantic received a B for regional planning, and experienced one of largest regional planning grade improvements since the 2023 Report Card. The Mid-Atlantic RTO, PJM Interconnection (PJM), has been working on reforms for more than two years to incorporate longer term planning into its regional transmission planning process.[120] In December 2025, PJM filed its Long Term Regional Transmission Planning (LTRTP) process, adopted to comply with Order No. 1920. PJM has also approved new, significant investments through its annual Regional Transmission Expansion Plans (RTEP).

PJM is facing some of the largest load growth in the county, largely driven by the rapid expansion of data centers and some new manufacturing facilities. Consistent with those trends, the 2024 RTEP approved new projects totaling nearly $6 billion, with most of the investment concentrated in two 765 kV projects that would extend PJM's extra-high-voltage backbone across West Virginia, Virginia, and Maryland. The 2024 transmission planning cycle also included more than $9 billion in supplemental projects.[121]

Early indications suggest the 2025 RTEP could be larger still. In December 2025, PJM previewed an approximately $11.6 billion transmission package expected to be considered for approval in Q1 2026 as part of the 2025 RTEP. The preliminary results reflect a substantial buildout, including more than 1,000 miles of 500 kV and 765 kV facilities through a mix of new greenfield lines, upgrades, and network reinforcements, with total costs exceeding $10 billion. Key drivers include continued load growth, particularly in Northern Virginia, and changes to previously planned projects. In particular, the New Jersey State Agreement Approach — which was intended to facilitate the interconnection of offshore wind — has been paused, increasing the need to move power from west to east to serve coastal demand that would otherwise have been met by offshore generation.[122] Major elements of the preliminary package include a new 765 kV line from West Virginia to central Pennsylvania, upgrades to portions of the 765 kV and 345 kV systems in Ohio, and a new 185-mile underground HVDC line in Northern Virginia (*see Fig. 16*).[123]

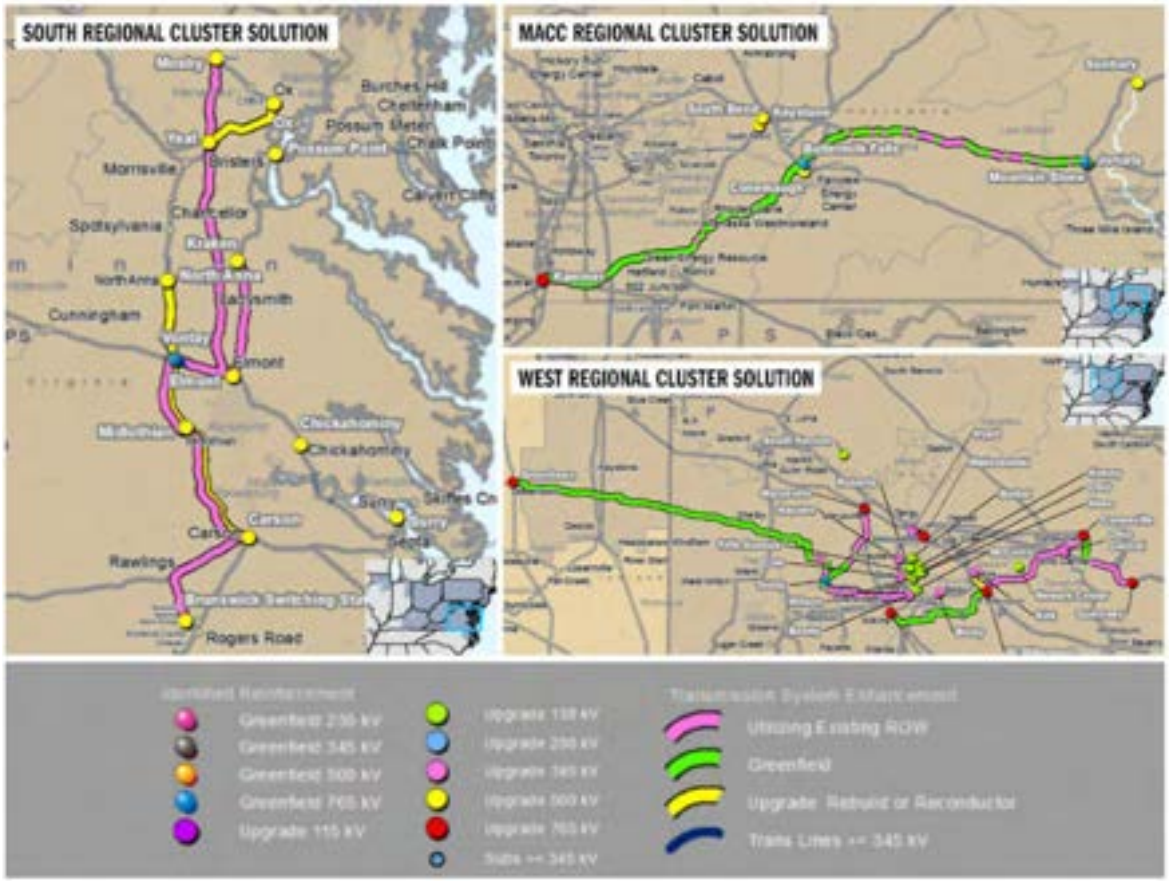
120 *See* 2023 Report Card at 29-31 and 2024 Interim Report Card at 18-21 for additional details on PJM's transmission planning.

121 PJM, *RTEP 2024* (Apr. 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

122 PJM, "New Jersey SAA Update" (Sept. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250909/20250909-item-01---new-jersey-saa-update.pdf.

123 PJM, *Reliability Analysis Report: 2025 RTEP Window 1* (Jan. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-2025-rtep-window-1-reliability-analysis-report.pdf.

**FIGURE 16** Preliminary Recommended Solutions by PJM Cluster[124]




The biggest improvement in PJM's grade compared to our last Report Card comes from their Order No. 1920 compliance filing. Our assessed grade assumes approval by FERC without significant changes to PJM's filing. The filing is intended to make tariff changes to codify PJM's LTRTP reforms and Order No. 1920 requirements. The new LTRTP process would add a 20-year planning horizon and capacity expansion modeling using at least three scenarios based on Order No. 1920's seven required factors. If implemented well, these changes will be a major improvement over PJM's current, more limited RTEP planning process, though additional action will still be required on the cost allocation funding due later in 2026.[125]

124 Leith-Yessian, D., " PJM Considering $11.6B Transmission Expansion Plan," RTO Insider (Dec. 2025), https://www.rtoinsider.com/121587-pjm-considering-11-6-b-transmission-expansion-plan/.

125 PJM, Order Nos. 1920, 1920-A, and 1920-B Compliance Filing of PJM Interconnection, L.L.C. and Request for Extension of Comment Period, Docket No. ER26-751-000 (Dec. 2025), https://www.pjm.com/pjmfiles/directory/etariff/FercDockets/9298/20251212-er26-751-000.pdf (Compliance Filing).

After developing and modeling the scenarios, PJM will parse the identified long-term transmission needs in two categories: Core Long-Term (LT) Needs and Additional LT Needs. Core LT Needs are designed to maintain system reliability, though they could address other drivers (such as economic congestion and public policy drivers). Additional LT Needs are any remaining needs that are identified but are not specific to maintain system reliability. PJM will identify which of these needs can be met by upgrading "right-sizing" existing facilities, and will open a competitive window to solicit new project proposals for any remaining needs in these two categories.

From the submitted and right-sized projects, PJM will develop a "Core Plan," comprised of the selected projects which will resolve the Core LT Needs. Transmission projects selected to address Core LT Needs will be evaluated on a portfolio basis to ensure they have a benefit-to-cost ratio great than or equal to one. PJM will then select additional transmission projects to address any Additional LT Needs that remain following selection of the Core Plan. Projects addressing Additional LT Needs must have an individual benefit-to-cost ratio of at least 1.25. Although full details are not yet available, PJM's proposed compliance includes the opportunity for states to opt-out of cost allocation for projects that only address Additional LT Needs.[126] Conversely, states and other parties will have the opportunity to voluntarily fund Additional LT Need projects that were not selected by PJM. PJM will then optimize the final plan based on the Core Plan and projects selected to address Additional LT Needs, which have not lost State support via the opt-out provision or those that are voluntarily funded, to create the All-In-One Plan, for approval by the PJM board.

The difference between the two planning categories is meant to show the incremental costs and benefits associated with developing projects beyond those needed just for reliability purposes (i.e. needed to meet Additional LT Needs). The incremental projects designed to address Additional LT Needs are not subject to the same mandatory selection criteria and must demonstrate a higher benefit-to-cost ratio on an individual project basis. The inequity and siloed nature of project selection based on need category is one reason PJM's new long-term planning approach did not score higher. However, the strength of PJM's process will be highly dependent on how PJM evaluates the factors and categorizes needs and solutions, and this grade may be revised in the future if the process is less siloed than it appears to be on paper. PJM will apply its existing RTEP criteria along with the required Order No. 1920 benefits to select projects in either plan.[127]

126 The language for the opt-out and voluntary funding will be included in the June 2026 cost allocation filing.
127 *See* Compliance Filing.

### New York

New York received a B+ for regional planning, and their regional planning grades remain largely unchanged from the 2023 Report Card as their proactive and holistic planning process remains in place under the New York Independent System Operator's (NYISO) Public Policy Transmission Planning Processes.[128] However, over the past year New York has faced some headwinds in its transmission planning, which could be cause for concern if prolonged. In July 2025, NYISO and the NY Public Service Commission (NYPSC) canceled its 2022-2023 Public Policy Transmission Planning Process, which was being used to develop the transmission needed to deliver new offshore wind resources to New York City.[129] In 2025, NYPSC also denied Clean Path Transmission's petition to be granted status as a priority transmission project,[130] a status available to the New York Power Authority and co-developers. The denial came after a termination of the contract with NYSERDA to develop associated generation via a renewable energy certificate at the end of 2024.[131] The project was designed to deliver 1,300 MW of power from new generation resources in upstate New York to New York City using an underground HVDC transmission line to help New York meet its state policy goals.[132]

As discussed in the 2024 Interim Update, NYISO completed its second biannual System & Resource Outlook ("Outlook") as part of its economic transmission planning.[133] For the second iteration, NYISO broadened the study to better inform the Coordinated Grid Planning Process (CGPP) by adding new scenarios and by flagging zones where congestion is likely to constrain renewable development. The Outlook also incorporated significant load growth assumptions, including a shift toward a winter peaking system in the mid-2030s, with large loads driving near-term growth before electrification of buildings and transportation becomes the larger driver later in the decade.[134] The Outlook is primarily informational, but it feeds into some local transmission solution and need determinations. NYISO is currently conducting the 2025-2044 Outlook, with preliminary results expected in early 2026.[135]

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128 *See 2023 Report Card at 36-38 and 2024 Interim Report Card at 32-37 for additional details on New York's transmission planning.*

129 New York Public Service Commission (NYPSC), "Commission Decision Avoids Premature Ratepayer Costs as a Result of Federal Uncertainty Decision Positions New York for Smarter, Faster Offshore Wind Growth When Federal Policies Improve" (Jul. 2025) https://dps.ny.gov/news/commission-acts-protect-ratepayers-federal-offshore-wind-permitting-stalls.

130 See NYPSC, "Order Denying Petition," Case 20-E-0197, 2-3 (Aug. 2025) https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10A1A998-0000-C42B-B3B8-0AB5C401EF82}&DocTitle=Order%20Denying%20Petition.

131 *Id.* at 7.

132 *Id.*

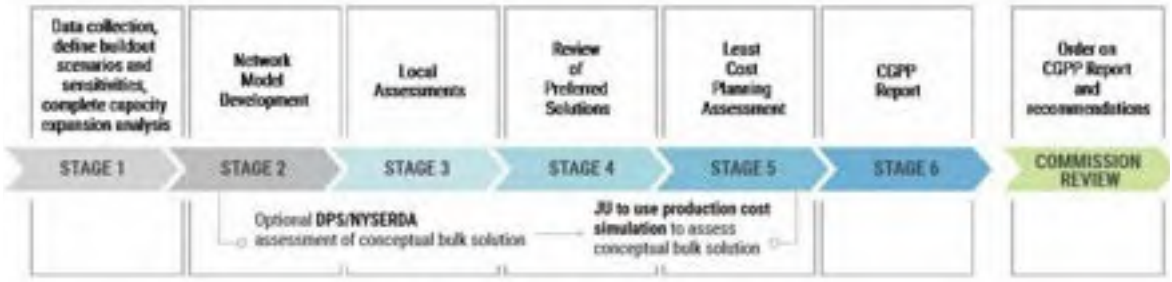
133 *See* NYISO, *2023-2042 System & Resource Outlook (The Outlook)* (Jul. 2024), https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf/8fb9d37a-dfac-a1a8-8b3f-63fbf4ef6167?t=1721752637474 ("2023-2042 System Outlook").

134 *Id.* at 13.

135 NYISO, "2025-2044 System & Resource Outlook Update," 4 (Dec. 2025), https://www.nyiso.com/documents/20142/55862442/2025-2044_System_Resource_Outlook_Update_12182025.pdf/80ef8110-1093-f1a7-cb31-9209e38faf44.

New York launched the CGPP in 2023 to better align utility local transmission planning with NYISO transmission planning and interconnection processes. The process follows a six-stage framework and is expected to culminate in an initial set of recommended investments for NYPSC consideration (*see Fig. 17).*[136] The first cycle timeline has slipped from late 2025 to May 2026.[137] Additionally, the NYPSC has already made process reforms to the CGPP based on stakeholder feedback, including moving to a two-year planning cycle.[138]

**FIGURE 17** Coordinated Grid Planning Process Timeline[139]




Within the CGPP, the NYPSC established the Advanced Technology Working Group (ATWG) to evaluate options such as Dynamic Line Ratings, Advanced Power Flow Control devices, and energy storage, with a 2024 NYPSC order directing the ATWG to consider a wider set of technologies and to allow submissions from interested parties.[140] In January 2025, the ATWG released its 2024 Annual Report summarizing the efforts from the previous year, mainly evaluating concept papers.[141] In 2025 the ATWG also took steps to more closely align with the CGPP and support the next planning cycle, including by developing screening criteria for each advanced transmission technology for the CGPP to apply to Stage 3 of the planning process.[142] The ATWG accepted another round of concept papers

136 System Outlook at 25; *See* also NYPSC, "Order Approving a Coordinated Grid Planning Process," Case 20-E-0197, August 17, 2023, at 24-25, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={101C058A-0000-C45D-9CD3-A87E49DF7A99}&DocTitle=Order%20Approving%20a%20Coordinated%20Grid%20Planning%20Process.

137 NYPSC, "Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act," Case 20-E-0197 (Dec. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F039379B-0000-CE3A-87EF-F5D1DD596792}&DocTitle=Ruling%20on%20Extension%20Request.

138 *See* NYPSC, "Order Modifying Coordinated Grid Planning Process" (Nov. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10517E9A-0000-C96B-B373-B6256DBE4622}&DocTitle=Order%20Modifying%20Coordinated%20Grid%20Planning%20Process.

139 2023-2042 System Outlook at 25.

140 *See* NYPSC, "Order Establishing Procedures for the Advanced Transmission Technologies Working Group," Case 20-E-0917, January 19, 2024, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B0E0228D-0000-C413-8A45-E2317EA6E16D}.

141 *See* Joint Utilities of New York, *Advanced Technology Working Group 2024 Annual Report* (Jan. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D047BD94-0000-CC11-AA01-95CA3727E1FA}&DocTitle=2024%20ATWG%20Annual%20Report.

142 Joint Utilities of New York, "Advanced Technology Working Group (ATWG) 2025 October Webinar," 16-17 (Oct. 2025) https://jointutilitiesofny.org/sites/default/files/Fall%202025%20Stakeholder%20Webinar%20Presentation%20(10.21.2025).pdf.

in late 2025 and is expected to release its second annual report in early 2026.[143]

### New England

New England received a B for regional planning, improving with the finalization of the Longer-Term Transmission Planning (LTTP) process, which was detailed in the 2024 Interim Report Card. The LTTP process was developed in two stages, which culminated in tariff changes that were approved by FERC in 2024.[144] The LTTP process is a proactive, holistic planning process that in its first study looked out to 2050 to address public policy transmission needs. The LTTP process also includes a broader set of benefits, though not the full Order No. 1920 set, and if the benefit-to-cost ratio was less than one, it allows for a state or a group of states to pay the difference.[145]

The process also includes the ability for states to solicit solutions to needs that are identified in the study. ISO New England (ISO-NE) and its states initiated that RFP process in 2024 with the first RFP window closing September 2025. The LTTP procurement requires proposals to increase the capacity of the Maine-New Hampshire interface to 3,000 MW and the Surowiec-South interface to 3,200 MW as well as support the interconnection of at least 1,200 MW of new resources in Northern Maine.[146] ISO-NE reported that there were six submissions to the RFP, three alternating current and three direct current projects, ranging between $962 and $4.04 billion, though these estimates will likely change as corollary upgrade cost estimates associated with the proposals are updated.[147] ISO-NE is in the process of evaluating the submissions, and project selection is expected in the second half of 2026.[148] ISO-NE has indicated additional RFPs may follow. In December 2025, the Maine Public Utility Commission, in collaboration with Connecticut, Massachusetts, Rhode Island, and Vermont, issued a related RFP to procure at least 1,200 MW of new transmission capacity to connect new generation in Northern Maine with ISO-NE. The Maine RFP project is expected to tie into the northern end of the ISO-NE LTTP RFP line, with in-service dates expected in the early 2030s.[149]

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143 *Id.* at 21.

144 *See* ISO New England, Inc. (ISO-NE), "ISO New England Inc. submits tariff filing per 35.13(a)(2)(iii): Revisions to the Attachment K Longer-Term Transmission Planning Process to be effective 7/9/2024 under ER24-1978," May 9, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240509-5064&optimized=false.

145 *See* 2023 Report Card at 34-36 and 2024 Interim Report Card at 26-31 for additional details on New England's transmission planning.

146 *See NESOE, "Transmission Needs for a Longer-term Transmission Planning RFP" (Dec. 2024),* https://www.iso-ne.com/static-assets/documents/100018/a05_2024_12_18_pac_transmission_needs_for_a_longer-term_transmission_planning_rfp_final.pdf.

147 *See* ISO-NE, "Longer-Term Proposals Summary" (Dec. 2025), https://www.iso-ne.com/static-assets/documents/100030/2025_lttp_rfp_proposal_summaries_rev1_clean.pdf.

148 ISO-NE, "2025 Longer-Term Transmission Planning Request for Proposals (2025 LTTP RFP)" (Nov. 2025), https://www.iso-ne.com/static-assets/documents/100029/a03_pac_2025_lttp_rfp_longer_term_summary_presentation.pdf.

149 *See* Maine Public Utilities Commission, "Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the Northern Maine Renewable Energy Development Program," Docket No. 2025-00361 (Dec. 2025), https://www.maine.gov/mpuc/regulated-utilities/electricity/rfp-awarded-contracts/2025-00361.

## 2. Interregional Transmission

The second grade component is interregional planning and development. This component — and the metrics associated with it — are based on very similar best planning practices to the regional transmission planning and development grade, including proactive generation and load forecasts, scenario- and portfolio-based planning, multi-value evaluation of transmission solutions, inclusion of alternative transmission technologies or business models (like merchant transmission developers), and interregional transmission planning that is integrated with other planning paradigms. This component also makes up 35% of the final grade.

As discussed in the introduction, there are very few formal requirements for interregional transmission planning. However, since the issuance of Order No. 1000, FERC has recommended stronger interregional transmission planning[150] and has held multiple workshops in 2016 and 2022 on the benefits of interregional transmission.[151] Additionally, in 2024, as discussed in the interim report card, NERC completed the Interregional Transfer Capability Study. The study was directed by Congress and focused solely on interregional transmission capacity additions needed for reliability.[152] NERC filed the study with FERC, where the public had an opportunity to comment. FERC must file the report plus its recommendations to Congress in early 2026,[153] but has not yet moved to take action on its own.

As such, many regions' interregional planning process consist solely of affected systems studies, which determine whether a neighboring transmission plan could impact the operational reliability of another system and would therefore be responsible for "do no harm" payments. Affected system studies are generally reliability-focused power flow models and do not include proactive, multi-value, scenario-based planning. Each regional discussion below considers whether regions are undertaking interregional transmission planning studies beyond the expected affected system studies.

### California

California received a B-, one of the highest grades for interregional transmission planning. While the region's formal interregional planning is limited, the region has taken some proactive measures to develop interregional transmission. For example, CAISO's recent

150 ScottMadden, "FERC Order No. 1000: Five Years On," 6 (Jun. 2016), https://www.scottmadden.com/content/uploads/2016/06/ScottMadden_FERC_Order_1000_2016_0601.pdf.

151 See FERC, "Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements," Docket AD23-3-000 (Dec. 2022), https://www.ferc.gov/news-events/events/technical-conference-regarding-competitive-transmission-development-rates-docket; *See also* FERC Competitive Transmission Development Technical Conference," Docket AD16-18-000 (Jun. 2016), https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

152 NERC ITCS at xix, 11.

153 "Notice of Request for Comments," FERC Docket No. AD25-4-000 (Nov. 2024), https://www.ferc.gov/sites/default/files/2024-11/20241125-3020_AD25-4-000-NERC%20ITCS%20Notice.pdf.

regional transmission plans have explicitly included estimates of out-of-state resources needed to help meet load growth and state policy goals, while maintaining reliability. The 2024-2025 CAISO Transmission Plan called for the "the import of over 9 GW of out-of-state wind generation from Idaho, Wyoming and New Mexico, by enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers."[154]

In the 2023 Report Card, we noted that CAISO had initiated the Subscriber Participating Transmission Owner (PTO) model as an innovative way to integrate out-of-state resources that California load-serving entities had procured. The Subscriber PTO model allows CAISO to develop transmission lines outside of its footprint and creates a cost recovery mechanism for developers. FERC approved the Subscriber PTO model in March 2024.[155] CAISO has approved two new transmission facilities under this model: TransWest Express and SunZia.[156] In January 2025 FERC approved a development agreement between CAISO and the Southwest Intertie Project (SWIP) North, where CAISO funds nearly 80% of the transmission project (Idaho Power will fund the remaining amount)[157] in exchange for assuming operational control of SWIP North and related One Nevada line.[158] In its 2024-2025 Transmission Plan, CAISO noted many of the challenges it is facing as it seeks to integrate out-of-state resources beyond the three lines above. The ISO highlighted that there are no interregional projects in development in the West seeking to deliver to CAISO, suggesting a lack of developer interest.[159] CAISO also notes the challenges of coordinating interregional transmission planning and cost allocation under the current formal interregional planning process, and has relied instead on the Voluntary Agreement Framework, outlined by FERC in 2018.[160]

However, CAISO also continues to participate in the Order No. 1000 interregional planning processes with NorthernGrid and WestConnect, despite no projects identified through those interregional processes.[161] In addition, CAISO is participating in an extensive Westwide transmission planning process, known as Western Transmission Expansion Coali-

154 CAISO 2024-2025 Transmission Plan at 7.

155 See Order Accepting Proposed Tariff Revisions re California Independent System Operator Corporation under ER23-2917, FERC Docket No. ER23-2917-001, March 12, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240312-3078&optimized=false.

156 CAISO 2024-2025 Transmission Plan at 127.

157 Idaho Power, "SWIP-North," accessed Jan. 2026, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/swip-north/.

158 *Id.*; See also Order Accepting Project Development Agreement, 190 FERC ¶ 61,034 (Jan. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250121-3068&optimized=false&sid=fa23f5ce-e93a-44aa-a547-d512ed245570; *See also* Order on Transmission Incentives and Accepting Transmission Owner Tariff and Formula Rate, 193 FERC ¶ 61,083 (Oct. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251031-3043&optimized=false&sid=cf779238-bd14-4f6b-86c8-939199233962.

159 *CAISO 2024-2025 Transmission Plan* at 128.

160 CAISO, "2025-2026 Transmission Planning Process," 30-39 (Sep. 2025), https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2025-2026-TransmissionPlanningProcess-Sep2525.pdf.

161 *Id.* at 157-158.

tion, discussed further below, and continues to explore mutually-beneficial transmission opportunities with other western utilities.

**Northwest & Southwest**

The Northwest and Southwest both received a C for interregional planning. Many of the transmission owners, states, and stakeholders from the NorthernGrid and WestConnect footprints — though, unlike in California, not the planning organizations themselves — are participating in WestTEC. WestTEC is a West-wide transmission planning study that emerged, at least in part, due to a lack of coordinated regional planning in the Western regions. The study has identified numerous interregional needs and upgrades and is one of the most robust interregional transmission planning processes in the country. Broad participation in WestTEC improved both regions' overall interregional transmission planning grades above what was earned by the limited, reliability and operational Order No. 1000 required interregional processes performed by NorthernGrid, WestConnect, and CAISO which has not identified any interregional needs.

***WestTEC Planning Process***

The WestTEC process is a proactive, scenario-based multi-value 10- and 20-year West-wide transmission plan, described in more detail in our 2024 Interim Report Card.[162] The WestTEC process is the only interregional transmission planning process that considers ATTs of any kind, though it has limited ATTs to only reconductoring with High Performance Conductors.[163]

The WestTEC planning process is on track to publicly release its 10-year transmission plan in Q1 of 2026 and has preliminarily identified 104 upgrades across the West (*see Fig. 18*). The upgrade list includes both new projects and some currently in development, all of which improve reliability, enhance interregional transfers, and/or provide congestion relief.[164] WestTEC plans to release the related 20-year transmission plan at the end of 2026.[165]

WestTEC process is currently informational only without a path to development of the project. There is no formal cost allocation or requirement for project selection, but there are some other efforts underway in the West. For example, the Committee on Regional Electric Power Cooperation Transmission Collaborative is working on an Order No. 1920

162 *See* 2024 Interim Report Card at 55-56 for additional details on the WestTEC's transmission planning process.

163 WestTEC, "Western Transmission Expansion Coalition," at 22-25 (Nov. 2025), https://www.westernpowerpool.org/private-media/documents/ES_REC_Update_-_251113.pdf.

164 *Id.* at 2.

165 *Id.*

cost allocation framework.[166] In addition, there is the Western Transmission Consortium composed of utilities and independent developers, which is aimed at developing bilateral, collaborative interregional or interjurisdictional transmission.[167] Both are positive developments, but neither is associated with WestTEC, and are unlikely to produce planning or create cost allocation functions in the same way a formal RTO would.

**FIGURE 18** WestTEC Preliminary 10-year Initial Transmission Plan[168]

## Texas

Texas received an F for interregional planning. The region is a separate electrical interconnection from the Eastern and Western United States and the grid operator, ERCOT, does not conduct regular interregional planning. ERCOT has jurisdictional independence, and its electricity is not considered interstate commerce under the Federal Power Act.[169] To avoid impacting ERCOT's jurisdictional status, any future interconnection must be specially built pursuant to a case-specific declaratory order from FERC, further complicating the process of developing interregional transmission. As was discussed in the 2023 Report Card, ERCOT, the Public Utility Commission of Texas, and the Texas legislature in the past have contemplated expanding or upgrading interregional transmission capacity with adjacent regions, but to date have not taken action.[170] There are a few re-

166 *See* Energy Strategies, *State Exploration of Western Transmission Cost Allocation, prepared for Western Interstate Energy Board & Committee on Regional Power Cooperation Transmission Collaborative* (Nov. 2024), https://www.westernenergyboard.org/wp-content/uploads/CREPC-TC-Cost-Allocation-Frameworks-White-Paper-FINAL-11-26-24.pdf.

167 Western Transmission Consortium, "The Western Transmission Consortium," accessed Jan. 2026, https://www.westerntransco.com/.

168 WestTEC, "Western Transmission Expansion Coalition," at 7.

169 Cottonwood Energy Co., LP, 118 FERC ¶ 61,198 (2007); Sharyland Utilities, LP, 121 FERC ¶ 61,006 (2007); Cross Texas Transmission, LLC, 129 FERC ¶ 61,106 (2009).

170 2023 Report Card at 50.

cently proposed merchant interregional lines to connect the Texas Interconnection with the rest of the country, but those have not arisen through a formal interregional planning process.[171] At this point, ERCOT earns the lowest grade for interregional planning.

### Plains

The Plains region received a C for interregional planning. The Plains is bordered by Canada, the Mid-Atlantic, Midwest, Northwest, Southwest, and Texas and to date has concentrated most of its interregional planning with efforts with the Midwest. The Plains and the Midwest continue to move forward with their Joint Targeted Interconnection Queue (JTIQ) portfolio through MISO and SPP planning. The regions have agreed to a Joint Operating Agreement and cost allocation methodology, which has been filed at FERC.[172] However, not all parties in MISO and SPP were supportive of the cost allocation structure, which proposes to allocate costs solely to developers.[173] The JTIQ portfolio was also awarded $464 million in the first round of DOE's Grid Resilience and Innovation Partnerships Program funding announced in October 2023. As of the end of 2025, the funding appears to still be in play; however, its long-term status is uncertain due to shifting administration priorities.[174]

The regions are moving forward assuming JTIQ will be built. In July 2025, FERC approved a MISO filing to allow the 2023 queue cycle to use the JTIQ process. That queue cycle began in September 2025. Additionally, the first cycle of MISO's Expedited Resource Addition Study kicked off in September. Interconnection requests in both MISO's Expedited Resource Addition Study and SPP's Definitive Planning Phase 2023 cycle have been identified as eventual projects that will fund the JTIQ portfolio once they enter into a Generator Interconnection Agreement and the appropriate JTIQ agreements.[175]

Both regions have indicated there will likely be a second round of planning. As discussed in the original report, this is a good step forward in aligning processes to work on joint planning and will facilitate the connection of nearly 30 GW of new generation. But the process falls short of true, optimized interregional planning, which would consider a more holistic set of transmission benefits beyond simply easing the interconnection process.

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171 *See* Pattern, "Southern Spirit Transmission," accessed Jan. 2026, https://patternenergy.com/projects/southern-spirit-transmission/; *See also*, Grid United, "Pecos West," accessed Jan. 2026, https://pecoswest.com/.

172 *See generally* tariff revisions and Joint Operating Agreement filings from SPP and MISO in FERC Docket Nos. ER24-2797-000, ER24-2798-000, ER24-2871-000, ER24- 2825-000, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240826-5149&optimized=false.

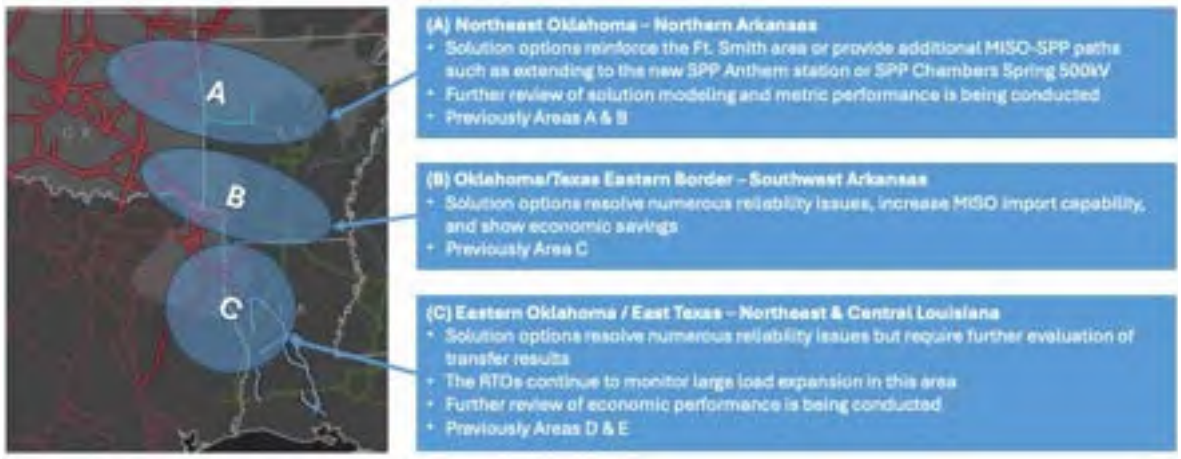
173 *See generally* Protest of the Clean Energy Associations to the 08/16/2024 filings of Southwest Power Pool Inc. et al. under ER24-2797, et al., https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240919-5161&optimized=false.

174 GDO, "Joint Targeted Interconnection Queue Transmission Study Process and Portfolio" (Oct. 2023); Durish Cook, A., "MISO Says JTIQ Tx Portfolio Stands — for Now," RTO Insider (Oct. 2025), https://www.rtoinsider.com/116917-miso-says-jtiq-tx-portfolio-stands-for-now/.

175 MTEP25 at 30.

MISO and SPP also attempted to conduct a new, enhanced Coordinated System Plan (CSP), which would incrementally enhance interregional transfer capabilities at their seam (*see Fig. 19*). The study was intended to identify near-term upgrades that incrementally enhance transfer capability, similar to the MISO-PJM study, but may also allow for the identification of transmission projects with multiple benefits.[176] As a part of the study, MISO and SPP requested a Joint Operating Agreement waiver, which was denied by FERC.[177] Despite the denial, MISO and SPP moved forward with the voluntary CSP study, which includes 10- and 15-year blended models of both operators' transmission systems based on MISO's Series 1A Future 2 and SPP's Future 2 models.[178] The final study model will include MISO's large load expedited project requests, Expedited Resource Addition Study generation additions, and SPP's reliability only future load.[179]

**FIGURE 19** MISO-SPP CSP Study Solutions Areas of Focus[180]




Based on the CSP modeling results, MISO opened a solicitation window and received 31 solutions, which were evaluated. From those 31 solutions, MISO and SPP down selected to 14 solutions, which received additional analysis using the updated blended models. Next steps for MISO and SPP are to finalize the business case methodology to demonstrate the multiple benefits of interregional transmission. The goal is to develop a methodology

176 SPP & MISO, "SPP-MISO Interregional Planning Stakeholder Advisory Committee," 6-12, (Dec. 2025), https://cdn.misoenergy.org/20251219%20MISO-SPP%20IPSAC%20Meeting732572.pdf ("SPP-MISO IPSAC").

177 *See* Petition of the Midcontinent Independent System Operator, Inc., and Southwest Power Pool, Inc. for Waiver of Tariff Provision, Docket No. ER25-943 (Jan. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250115-5170&optimized=false&sid=4b18f9da-543c-467a-b0a6-19050e7a220a; Order Denying Waiver Request, 192 FERC ¶ 61,004 (Jul. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250702-3095&optimized=false&sid=4b18f9da-543c-467a-b0a6-19050e7a220a ("Order Denying Waiver Request").

178 SPP-MISO IPSAC *at 6-12.*

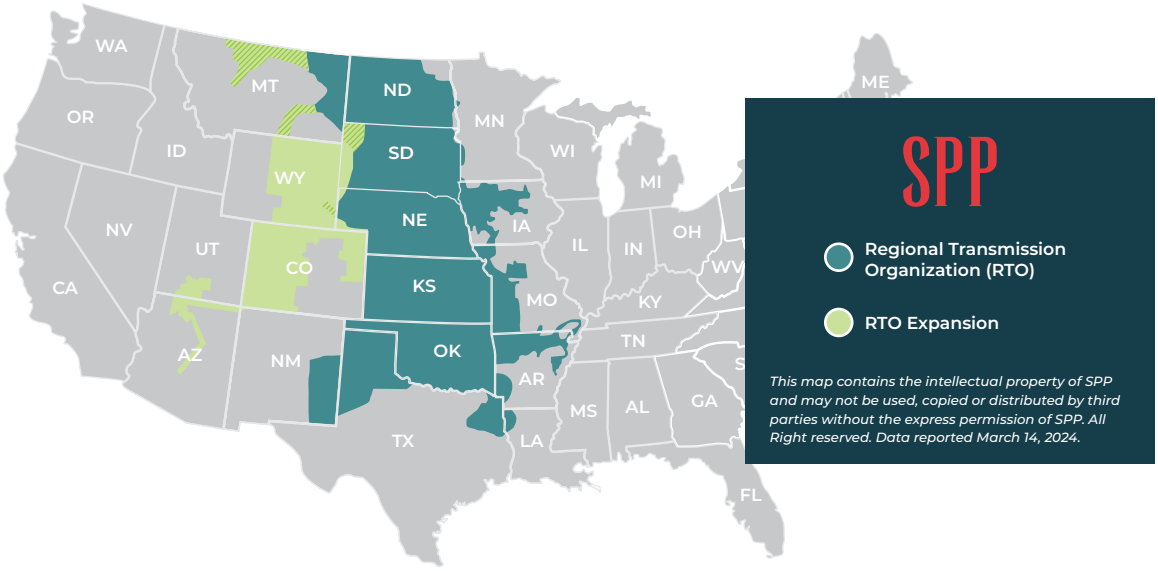
179 *Id.* at 8-9.

180 *Id.* at 16.

aligned with the seven economic and reliability benefits in Order No. 1920. A draft report including solution recommendations is expected in March 2026; after which, SPP and MISO may decide to further develop the CSP projects requiring the new interregional cost allocation and Joint Operating Agreement changes, which would have to be filed with and approved by FERC.[181]

In 2025, FERC also approved SPP's expansion under its RTO West plan (*see Fig. 20*). The plan will expand the RTO's footprint into the Western Interconnection effective in the first half of 2026. As of now, the Eastern Interconnection region and Western Interconnection region of SPP will be connected by three DC interties totaling just over 0.5 GW.[182] Depending on how transmission planning is executed with the expansion, it could lead to interregional transmission expansion with the non-RTO west and could improve the grade in future Report Cards.

**FIGURE 20** Expansion of the SPP RTO[183]




## Midwest

The Midwest received a B- for interregional planning. The Midwest is bordered by Canada, the Mid-Atlantic, the Northwest, the Plains, the Southeast regions, and Texas. The

181 *Id.* at 7.

182 SPP, "SPP first RTO to operate in both interconnections with tariff approval" (Mar. 2025), https://www.spp.org/news-list/spp-first-rto-to-operate-in-both-interconnections-with-tariff-approval/.

183 SPP, "Expansion of the SPP RTO" (Nov. 2020), https://www.spp.org/documents/63373/spp%20rto%20west%20expansion%2020201111%20announcement%20v2.png.

Midwest has taken steps to improve interregional transmission planning and increase interregional transfer capacity, both through its regional planning process and existing interregional planning, in particular with the Plains and Mid-Atlantic.

MISO's LRTP Tranche 2.1 includes several 765 kV transmission lines that will connect with PJM's existing 765 kV system. PJM is currently conducting an affected systems study for the Tranche 2.1 portfolio. Preliminary results indicate there are just over $120 million in reinforcement upgrade costs (*see Fig. 21*).[184] MISO is currently negotiating a universal construction, cost allocation, and funding agreement with the constructing PJM transmission owners, which will be filed with FERC. An update is expected in the first quarter of 2026.[185] More on the interregional transmission planning efforts initiated by MISO are covered in its neighbors' sections — the Plains and Mid-Atlantic.

**FIGURE 21** Preliminary PJM Identified Upgrades for MISO's Tranche 2.1[186]

## Southeast

The Southeast received an F for interregional planning. The region performs affected systems studies with its neighboring regions and also participates in the Eastern Interconnection Planning Collaborative (EIPC), which includes all Eastern Interconnection regions (New England, New York, the Midwest, Mid-Atlantic, Plains, and Southeast).[187] The EIPC performs Interregional Transfer Capability studies to identify constraints and evalu-

184 PJM & MISO, "MISO Tranche 2.1 Evaluation Update," 4 (Dec. 2025), https://cdn.misoenergy.org/20251205%20MISO-PJM%20IPSAC%20Item%2002%20Tranche%202.1%20Update730296.pdf.

185 *Id.* at 5.

186 *Id.* at 4.

187 Eastern Interconnection Planning Collaborative (EIPC), accessed Jan. 2026, https://eipconline.com/.

ate how regional transmission plans mesh to maintain the reliability of the bulk electric system. These studies are not intended to identify specific transmission projects to increase transfer capability.[188] At the end of 2024, Southern Company, Santee Cooper, and Dominion Energy South Carolina did announce a joint study to determine "efficient and cost-effective projects to increase interregional transfer capability" and to accommodate resource changes. However, there have been no updates on the study, and it is not clear if any developments have arisen.[189] In general, the interregional studies that the Southeast is involved in are focused solely on regional reliability impacts, and to the best of our knowledge, there is little proactive interregional transmission planning occurring. The results of these studies may warrant a higher grade in the future, but there is little transparency into their current processes or interim results.

### Mid-Atlantic

The Mid-Atlantic received a D+ for interregional planning. The Mid-Atlantic is bordered by New York, the Midwest, and the Southeast. Currently, the Mid-Atlantic is doing little to no proactive, scenario-based interregional transmission planning with the Southeast or New York.

However, in conjunction with the Midwest, the Mid-Atlantic initiated a new, limited — but innovative — joint Interregional Transfer Capability Study (MISO/PJM ITCS). The goal of the study is to identify projects near the MISO-PJM seam that can incrementally enhance interregional transfer capabilities. The MISO/PJM ITCS study used a blended model that reflected proactive transmission, load, and resource additions for both regions. However, the MISO/PJM ITCS only included contracts for existing generators sending power across the seam and did not model expanded cross-seams generation sales or transfers. This significantly limits the amount of transmission that could be modeled or built. The transmission topology also included merchant HVDC facilities with executed Interconnection and Facilities Construction Agreements.[190] Based on the blended model, MISO and PJM then conducted a reliability, transfer, economic, and extreme weather analysis identifying 22 issues that arose across all areas of analysis. MISO solicited conceptual projects from stakeholders, which included upgrades and new corridors (*see Fig. 22).*[191] In part, PJM did not also solicit projects because their sponsorship model constrains solution

188 EIPC, *EIPC Interregional Transmission Transfer Capability Study Report*, 8-10 (Sep. 2025), https://eipconline.com/s/EIPCITCSTUDYREPORT-FINAL9-10-25-1.pdf.

189 SERTP, "4th Quarter Meeting Annual Transmission Planning Summit & Assumptions Input Meeting," 209 (Dec. 2024), https://www.southeasternrtp.com/docs/general/2024/2024_SERTP_4th_Qtr_Presentation.pdf.

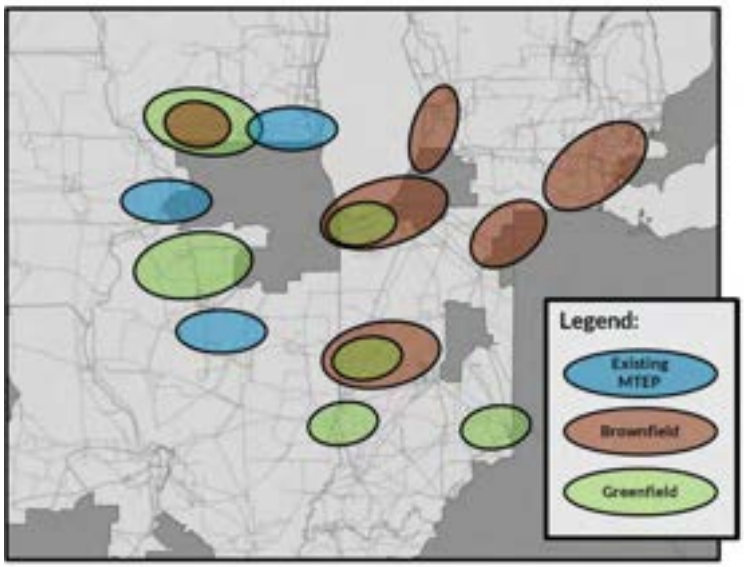
190 The study relied on PJM's LTRTP Workshop Policy Study 2032 model and MISO's Series 1A Futures Report. *See* PJM & MISO, "PJM/MISO Interregional Transfer Capability Study," 5 (Jun. 2025), https://cdn.misoenergy.org/20250625%20MISO-PJM%20IPSAC%20Item%2002%20ITCS%20Update704126.pdf ("PJM/MISO ITCS").

191 *Id.* at 18-19.

development until after final needs are identified and posted.

Both PJM and MISO recognized neither organization has a project category, nor an associated cost allocation methodology, to capture the full suite of benefits provided (i.e. economic, reliability, and transfer capability) by the solutions evaluated in the MISO/PJM ITCS process.[192] The next step for these regions is to develop an interregional transmission benefits evaluation methodology in the first half of 2026 and then an RTO-RTO cost allocation methodology.[193]

**FIGURE 22** Target areas of conceptual solutions submission and alternatives that MISO recommends for further evaluation in the MISO/PJM ITCS[194]




### New York & New England

New York received a C+ and New England received a C for interregional planning. The regions are neighbors bordered by Canada and the Mid-Atlantic. New York and New England are both active in interregional transmission planning, including the Northeast Grid Planning Forum, which recently released the Eastern Canada-NE US Interregional Planning Roadmap.[195]

Both NYISO and ISO-NE consider different import scenarios in their regional planning processes, the Outlook and LTTP studies, respectively. In its 2032-2042 Outlook, NYISO conducted a limited evaluation of potential resource exports to determine if New York can achieve its policy goals.[196] ISO-NE considers both HVDC imports from Canada and

192 PJM & MISO, "PJM/MISO Interregional Transfer Capability Study," at 30-35 (Dec. 2025), https://cdn.misoenergy.org/20251205%20MISO-PJM%20IPSAC%20Item%2003%20ITCS%20Update730297.pdf.

193 PJM/MISO ITCS at 2-5.

194 MTEP25 at 28.

195 *See* Power Advisory, *Eastern Canada-NE US Interregional Planning Roadmap, prepared for Northeast Grid Planning Forum* (Aug. 2025), https://acadiacenter.wpenginepowered.com/wp-content/uploads/2025/09/Eastern-Canada-Northeast-U.S.-Interregional-Transmission-Planning-Roadmap_25.08.07.pdf.

196 2023-2042 System Outlook at 67-71; *See also*, NYISO, *2023-2042 System & Resource Outlook: Appendix I: Transmission Congestion Analysis* (Jul. 2024) https://www.nyiso.com/documents/20142/46037616/Appendix-I%20-Transmission-Congestion-Analysis.pdf/a3a7beed-1e4b-125d-eb42-442f1a1189d4.

additional connections with NYISO as a part of its 2050 Transmission Study (*see Fig. 23).*[197] However, these scenarios are generally information only or do not have any associated selection mechanism or cost allocation.

**FIGURE 23** ISO-NE 2050 Transmission study roadmap for limited interregional and HVDC additions[198]

Both regions do allow for significant independent interregional transmission lines to be planned and developed, with several lines connecting to Canada expected to be energized in 2026.[199] Financial support for independent interregional transmission development is often sourced from New York and the northeastern States, which require interregional transmission development to accomplish state legislative aims.

Momentum for interregional transmission has been growing in NYISO and ISO-NE in recent years. For example, in July 2024, nine states, including New York, most New England states, and some PJM states, announced they would participate in the Northeast States Collaborative on Regional Planning.[200] The states signed a Memorandum of Understanding which "establishes a non-binding framework to coordinate enhanced interregional transmission planning and development."[201] A key component of this memorandum is better coordination on the planning and development of transmission to support offshore wind generation. The states developed a strategic action plan, published in April

197 ISO-NE, "2050 Transmission Study" (Feb. 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

198 *Id.* 33 & 44.

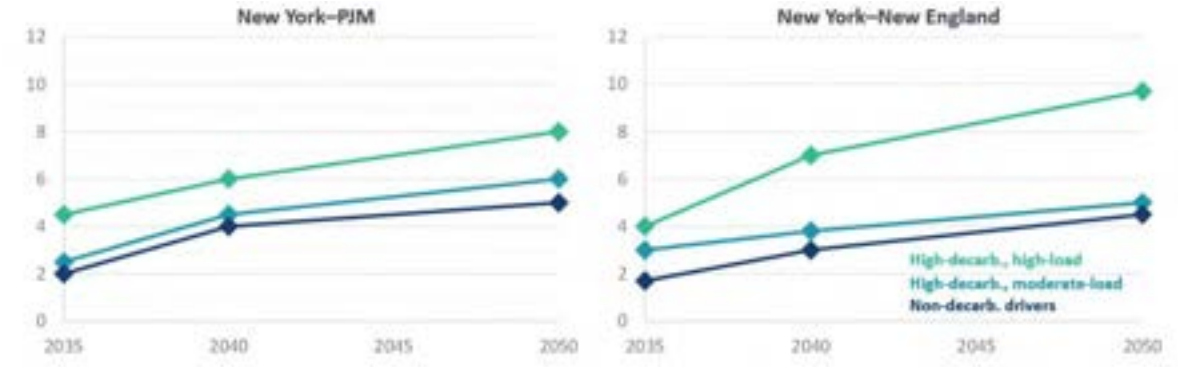
199 New England Clean Energy Connect was energized in Jan. 2026, Avangrid, "Avangrid's New England Clean Energy Connect Project Is Complete and Energized" (Jan. 2026), https://www.avangrid.com/w/avangrid-s-new-england-clean-energy-connect-project-is-complete-and-energized; *See also* New England Clean Energy Connect, accessed Jan. 2026, https://www.necleanenergyconnect.org/; See also Champlain Hudson Power Express, accessed Jan. 2026, https://chpexpress.com/.

200 Johns Hopkins, "Northeast States Collaborative on Interregional Transmission," accessed Jan. 2026, https://energyinstitute.jhu.edu/northeast-states-collaborative-on-interregional-transmission/.

201 Northeast States Collaborative on Interregional Transmission, "Memorandum of Understanding," 1 (Jul. 2024), https://energyinstitute.jhu.edu/wp-content/uploads/2024/07/MOU-Northeast-States-Collaborative-on-Interregional-Transmission.pdf.

2025, which estimated their interregional transmission expansion needs (*see Fig. 24*).[202] Following this release, the collaborative released an RFI seeking interregional projects that would increase transfer capacity between at least two of the regions involved.[203]

**FIGURE 24** Estimated range of low-regret interregional transmission expansion needs (GW)[204]




A negative development related to interregional planning for New England, New York, and the Mid-Atlantic was the decision by ISO-NE to pause its study to find solutions to increase ISO-NE's 1,200 MW loss of source limit with NYISO and PJM.[205] The study, initiated by ISO-NE, was narrowly focused on ISO-NE's 1,200 MW loss of source limit. ISO-NE concluded that it was not currently feasible to raise the loss of source limit to 2,000 MW and found that upgrades were required along the New York and New England interface, though more study is required.[206] Abandoning this study and foregoing identification of transmission upgrades needed to raise the loss of source limit potentially impacts the viability of future HVDC projects that would likely benefit from a higher limit.

## 3. Engagement

The third grade component is engagement. This component, and the metrics associated with it, are based on stakeholder engagement, transparency, the role for states and their regulators, and effective cost allocation for regional and interregional transmission development. This component makes up 15% of the final grade.

202 *Id.* at 3; See The Brattle Group, *Strategic Action Pan*, prepared for Northeast States Collaborative on Interregional Transmission (Apr. 2025), https://energyinstitute.jhu.edu/wp-content/uploads/2025/04/Strategic-Action-Plan-Final.pdf.

203 *See* Northeast States Collaborative on Interregional Transmission, "Request for Information on State-Led Interregional Transmission Projects" (Jun. 2025), https://energyinstitute.jhu.edu/wp-content/uploads/2025/06/Northeast-States-Collaborative_RFI_FINAL-6_20_25.pdf.

204 *Strategic Action Plan* at 3.

205 ISO-NE, "Letter to Joint ISO/RTO Planning Committee (JIPC)" (Mar. 2023), https://www.iso-ne.com/static-assets/documents/2023/03/jipc_loss_of_source_limit_final.pdf; JIPC, "JIPC Response to ISO New England's Request for Raising ISO New England's Minimum Loss of Source Value" (Aug. 2023), https://www.iso-ne.com/static-assets/documents/2023/08/2023_08_23_jipc_response_to_iso_letter.pdf.

206 ISO-NE, "Interregional Study Update: Increasing New England Loss of Source Limit" (Dec. 2025), https://www.iso-ne.com/static-assets/documents/100030/a02_2025_12_05_ipsac_iso_loss_of_source.pdf.

### California

California received an A- on Engagement, and is a single-state region, which means there is a clearer relationship between California state entities and regional planners at CAISO. There is extensive coordination between CAISO's transmission planning processes and California state agencies, including the California Energy Commission and the California Public Utilities Commission.[207] The Commission hosts numerous stakeholder advisory committees that support the state and CAISO in its transmission planning processes. CAISO uses a public stakeholder initiative process to develop new policy, beginning with an issue paper which goes through several stakeholder revisions until a final proposal is presented to for CAISO Board of Governors approval.[208] Stakeholders submit written comments and participate in meetings at each stage, but there is no formal sector voting; instead, staff considers comments and elevates a recommendation. Final decisions to adopt market or tariff changes rest with the CAISO Board, which determines whether to proceed with a regulatory filing.[209] For regional transmission projects, CAISO utilizes an effective postage stamp cost allocation method where costs are allocated on load ratio basis.[210] CAISO's cost allocation also includes the Subscriber PTO model, which was approved by FERC in March 2024, and allows CAISO to develop transmission lines outside of its footprint and creates a cost recovery mechanism for developers.[211] See further discussion of the Subscriber PTO model in the interregional planning section.

### Northwest

The Northwest received an F on Engagement. The Northwest transmission owners created NorthernGrid to conduct Order No. 1000 regional planning. NorthernGrid includes investor-owned FERC-jurisdictional utilities and publicly owned utilities that are not FERC-jurisdictional and voluntarily participate. NorthernGrid's planning process is largely driven by its members. NorthernGrid does have a limited role for state regulators through the Enrolled Parties Planning Committee and States Committee. State regulators are provided a vote in the planning process via the Committees but are not allowed to modify the tariff. Non-utility stakeholders can participate in public meetings and provide com-

207 *See generally* CPUC, CEC, and CAISO Planning MOU.

208 FERC, "Understanding and Participating in California ISO (CAISO) Processes," accessed Jan. 2026, https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

209 CAISO, "Policy initiatives and stakeholder process," accessed Jan. 2026, https://stakeholdercenter.caiso.com.

210 Kahrl, K. et al, *Transmission Cost Allocation Practices, Lawrence Berkeley National Laboratory*, 3 & 20 (May 2025), https://eta-publications.lbl.gov/sites/default/files/2026-01/transmission_cost_allocation_brief_final_v2.pdf ("Transmission Cost Allocation Principles").

211 *See* Order Accepting Proposed Tariff Revisions re California Independent System Operator Corporation under ER23-2917, FERC Docket No. ER23-2917-001, March 12, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240312-3078&optimized=false.

ments on plans.[212] Though as discussed in the regional planning section, NorthernGrid regional plans are not intended to be construction plans.[213] The region has yet to develop a regional or interregional line using the NorthernGrid planning and cost allocation process.[214]

The Northwest also includes BPA, which owns 75% of the region's high-voltage transmission system. Historically, despite not being subject to FERC oversight, BPA voluntarily adopted FERC open access and tariff standards.[215] However, in 2013 FERC denied BPA "safe harbor reciprocity status," and in 2016 BPA decided that rather than make further changes to its OATT to align with FERC requirements, it would drop its safe harbor reciprocity status.[216] BPA remains a voluntary participant with a significant role in NorthernGrid given the size of its transmission system, but does not have to comply with FERC Orders No. 2023 and 1920. However, in recent years, BPA has recognized the increasing need for transmission and need to reform many of its planning processes. BPA has begun to develop a limited number of transmission projects through its Grid Expansion and Reinforcement Portfolio.[217] BPA has also held initial workshops in preparation for a formal tariff revision process that will reform how BPA conducts cluster studies of customer transmission service requests and is hosting a series of workshops as a part of its Grid Access Transformation project to determine the future of its transmission planning.[218]

In the non-market regions states do not have the same formalized regional state committees with dedicated staff. And while it is no substitute, the West does have numerous bodies outside of the region that provide some staff support and technical expertise to states including the Western Interstate Energy Board, which also supports the Committee on Regional Electric Power Cooperation, the Western Interconnection Regional Advisory Body, the Western Energy Imbalance Market Body of State Regulators, and the Western Resource Adequacy Program Committee of State Representatives.[219]

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212 Northwestern, "Attachment K Transmission Planning Process," 83-95 (Jan. 2022), https://www.northerngrid.net/private-media/documents/Att_K_-_Transmission_Planning_Process_ROdZrBy.pdf.

213 *Id,* at 28.

214 *See* 2023 Report Card at 38-40.

215 NIPPC and Renewable Northwest, "'Appropriate and Required': BPA and Building the Grid the Northwest Needs," 15-17 (May 2023), https://renewablenw.org/sites/default/files/Reports-Fact%20Sheets/BPA%20Tx%20Whitepaper%2005.03.2023.pdf.

216 *Id.*

217 BPA, "Grid Expansion and Reinforcement Portfolio (GERP)," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-expansion-and-reinforcement-portfolio.

218 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project; *See also* BPA, "TC-27 Tariff Proceeding," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/tc-27-tariff-proceeding.

219 Concurrence by Commissioner Christie and Commissioner Rosner to the Order Accepting Proposed Tariff, Subject to Condition, 190 FERC ¶ 61,030 (Jan. 2025), https://www.ferc.gov/media/e-1-er24-1658-000.

**Southwest**

The Southwest received an F on Engagement. The Southwest regional transmission planning process occurs on a two-year cycle, through WestConnect, and evaluates a 10-year planning horizon. WestConnect is the Order No. 1000 regional planning entity and includes FERC-jurisdictional utilities (Enrolled Transmission Owners) for the purposes of cost allocation under Order No. 1000. The WestConnect regional transmission planning process is largely driven by its ETOs. All committees in WestConnect report to the Planning Management Committee. The Planning Management Committee does include roles for State Regulatory Commissions and Key Interest Groups. In the 2023 Report Card, those seats were vacant but have since been filled, which is an improvement.[220]

WestConnect has three Subregional Planning Groups: the Southwest Transmission Planning Group, the Sierra Subregional Planning Group, and the Colorado Coordinated Planning Group. The ETOs participate within these groups, but the Subregional Planning Groups do not perform any of the regional planning functions. The ETOs develop the base cases for the regional transmission study by reviewing and updating WECC base case models. WestConnect has yet to develop a regional or interregional line using its regional planning and cost allocation processes.[221]

Since the 2023 Report Card, litigation surrounding WestConnect's Order No. 1000 planning has been resolved.[222] In response to a court decision, FERC ordered WestConnect to remove the Coordinating Transmission Owner framework from their OATT, which was a unique framework that allowed nonpublic utility members to participate in the regional transmission planning process. This is because once projects are selected in a regional plan, the Coordinating Transmission Owners could choose to not pay for the costs of the projects they would be allocated, which was determined to be incompatible with cost causation principles. In April 2025, FERC accepted the ETOs' amended OATT, which revised WestConnect's regional transmission planning process to only conduct regional transmission planning for enrolled transmission providers because they are subject to binding cost allocation.[223]

While the removal of non-jurisdictional transmission owners was mandated by FERC, the result has undermined the effectiveness of regional planning in the Southwest as West-

220 WestConnect, "Regional Planning: Planning Management Committee Members," accessed Jan. 2026, https://regplanning.westconnect.com/pmc_members.htm.

221 *See 2023 Report Card* at 45-47.

222 El Paso v. FERC (2023), https://www.ca5.uscourts.gov/opinions/pub/18/18-60575-CV0.pdf; *See also* Order on Remand, 189 FERC ¶ 61,028 at P 19 (2024) & Order Accepting Tariff Revisions and Terminating Section 206 Proceedings, 191 FERC ¶ 61,074 (2025).

223 WestConnect Enrolled Transmission Owners, "Letter to WestConnect on Non-Tariff Activities for the Remainder of 2025" (Jun. 2025), https://doc.westconnect.com/Documents.aspx?NID=21407&dl=1.

Connect's planning footprint now includes substantial gaps. WestConnect's 2024-2025 regional plan only identified transmission needs affecting multiple participating entities, and unless the region develops other ways to collaborate on planning, future planning cycles will not identify potential regional needs between FERC-jurisdictional utilities and federal power agencies, municipal utilities, or cooperative utilities.

### Texas

Texas received a B on Engagement, and is a single-state region, which means there is a clearer relationship between Texas state entities and regional planners at ERCOT. Texas is also different because ERCOT operates a separate electrical interconnection from the rest of the U.S. that is intrastate and not subject to FERC jurisdiction for market rules. Ultimate approvals occur under Texas oversight via the ERCOT Board and the Public Utility Commission of Texas.[224] Texas' stakeholder process in ERCOT is centered on the Protocol Revision Subcommittee and the Technical Advisory Committee. It uses segment-based voting (generators, transmission/distribution utilities, retail electric providers, consumers, municipals/co-ops, and others). Thresholds vary by body, and recommendations move to the ERCOT Board who has ultimate approval.[225] For regional transmission projects ERCOT utilizes a postage stamp cost allocation method. As discussed in the 2024 Interim Report Card, limitations to the economic planning test mean almost all projects arise through reliability planning.[226] In addition, Senate Bill 6, which passed in 2025, directed the Public Utility Commission of Texas to evaluate existing transmission cost allocation and recovery methods.[227] The PUCT's process kicked off in August 2025.[228]

### Plains

The Plains received a B on Engagement. The region has balanced regional stakeholder and state engagement through SPP and a significant stakeholder process, which includes multiple committees and working groups, such as the Strategic Planning Committee, the Transmission Working Group, the Economic Studies Working Group, the Cost Allocation Working Group, the Regional State Committee, and the Markets and Operations Policy Committee.[229] SPP's process is notably stakeholder-driven with working

224 *See* ERCOT, "Stakeholder Process Overview" (Jan 2021), https://www.ercot.com/files/docs/2021/01/05/05.__Stakeholder_Process_Overview_010721.PPTX.

225 ERCOT, "Governance," accessed Jan. 2026, https://www.ercot.com/about/governance; ERCOT, "Committees and Groups," accessed Jan. 2026, https://www.ercot.com/committees.

226 *Transmission Cost Allocation Principles* at 3.

227 89th Tex. Leg., R.S., Senate Bill 6, § 6 (effective June 20, 2025).

228 *See generally* Public Utility Commission of Texas, Project Number 58484, accessed Jan. 2026, https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=58484.

229 FERC, "An Introductory Guide for Participation in Southwest Power Pool Processes," accessed Jan. 2026, https://www.ferc.gov/introductory-guide-participation-southwest-power-pool-processes.

groups developing recommendations that move to the Markets and Operations Policy Committee. Markets and Operations Policy Committee often uses sector or weighted voting with supermajority thresholds before forwarding items. Both the Regional State Committee (RSC) and the SPP Board must approve major changes, and the Board decides what to file with FERC.[230] While SPP's RSC has no full-time independent staff, the RSC is a formal committee with the Section 205 filing rights for both cost allocation and resource adequacy.[231]

SPP also has an effective cost allocation methodology for regional transmission planning, utilizing a type of regional postage-stamp cost allocation methodology, called the Highway/Byway cost allocation method, which allows SPP to regionally allocate the costs for transmission facilities at or above 300 kV.[232]

In 2025, MISO and SPP attempted to get a waiver to their Joint Operating Agreement to conduct a more robust interregional Coordinated System Plan with MISO but were denied the waiver by FERC. Both regions have indicated that it will likely pursue tariff changes for interregional cost allocation and project selection with MISO.[233]

**Midwest**

The Midwest received a B+ on Engagement. The region has regional stakeholder and state engagement through MISO, which has three main stakeholder committee groups that participate in transmission planning, including several sub-regional planning committees, the Planning Subcommittee, and the Planning Advisory Committee.[234] MISO uses a comprehensive planning process that involves many stakeholders. Participation is organized through working groups and subcommittees that feed into the Advisory Committee. The Advisory Committee uses sector-based voting in which sectors cast positions and forward recommendations to the MISO Board. These recommendations are influential but advisory; the Board ultimately determines what is filed with FERC.[235]

MISO's RSC is known as the Organization of MISO states (OMS) and exists outside of the RTO with a few full-time staff. OMS does not have "jump-ball" filing rights but does have complementary Sec. 205 filing rights for transmission cost allocation. This means MISO

230 *See* Exeter Associates, Inc., *Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs, prepared for NESCOE* (Feb. 201), https://nescoe.com/wp-content/uploads/2021/02/ISO-RTOGovernanceStructureandPractices_19Feb2021.pdf ("Governance Structure and Practices").

231 Clements, A., "Making Sense of Potential Western ISO Governance Structures: The Role of the State," 4 (Jun. 2016), https://www.nrdc.org/sites/default/files/potential-western-iso-governance-structures-ib.pdf ("Making Sense of Potential Western ISO Governance").

232 Sw. Power Pool, Inc., 131 FERC ¶ 61,252 (2010) (Highway/Byway Order), reh'g denied, 137 FERC ¶ 61,075 (2011).

233 *See* Order Denying Waiver Request.

234 FERC, "Participation in Midcontinent Independent System Operator (MISO) Processes," accessed Jan. 2026, https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes.

235 *See Governance Structure and Practices.*

can develop, amend, or review changes to regional cost allocation methodology. IF OMS can obtain a supermajority, it can request that MISO file alternative or modified cost allocation proposal with FERC. However, MISO does not have to make the filing but must provide a written explanation as to why it did not.[236]

MISO has developed a Multi-Value Project cost allocation methodology, which it uses for its LTRP process, and as discussed above, MISO has indicated that it will likely pursue tariff changes for interregional cost allocation with PJM as well as with SPP after FERC denied MISO and SPP's joint waiver request earlier in 2025.[237]

### Southeast

The Southeast received an F on Engagement. In the Southeast, a key hurdle for regional transmission planning is the lack of access to information and transparency. SERTP, SCRTP, and FRCC's opaque processes limit the effectiveness of stakeholder engagement in transmission planning. In FRCC, for example, most published information is behind a password-protected website, and there is very limited opportunity for stakeholder engagement or influence. SCRTP does include a list of their planned projects with costs for everything above $2 million, but for everything else a nondisclosure agreement or Critical Energy Infrastructure Information clearance is needed to access nearly all transmission planning outcomes. In SERTP, for the 2025 planning cycle, transmission owners did provide limited access to cost estimates, though access required a nondisclosure agreement, like most of the planning assumptions and details, and the cost information was not allowed to be used elsewhere. In SERTP and SCRTP, state regulators and stakeholders also have little influence or ability to participate in the planning process or outcomes.[238] Similar to the Northwest and Southwest regions, states in the Southeast do not have the same formalized regional state committees with dedicated staff as in organized markets. However, unlike the Northwest and Southwest, the Southeast does not have numerous bodies that provide support and technical expertise to the states.

### Mid-Atlantic

The Mid-Atlantic received a B on Engagement. The region conducts regional transmission planning predominantly through the PJM Transmission Expansion Advisory Committee.[239] In PJM, transmission planning is governed by the PJM Operating Agreement

236 Gardner, J., "RTO Governance Models: The Role of States," 11 (Apr. 2019), https://westernenergyboard.org/wp-content/uploads/2019/04/04-17-19-eim-bosr-gardner-rto-governance-models-role-of-states.pdf; *See also "Making Sense of Potential Western ISO Governance" at 3-4.*

237 *See* MISO, *Attachment FF - Transmission Expansion Planning Protocol* (Jan. 2026), https://docs.misoenergy.org/miso12-legalcontent/Attachment_FF_-_Transmission_Expansion_Planning_Protocol.pdf; See also Order Denying Waiver Request.

238 *See 2023 Report Card* at 42-45.

239 PJM, "Transmission Expansion Advisory Committee," accessed Jan. 2026, https://www.pjm.com/committees-and-groups/committees/teac.

which keeps some section 205 filing rights with PJM's Transmission Owners, such as transmission cost recovery and rate design.[240] As a part of the Operating Agreement, to make changes to transmission planning, PJM must get approval from the PJM Members Committee, which uses a sector-weighted model in which each sector casts one vote, and supermajority support is typically required for endorsement.[241] However, the PJM board, if it believes part of the Operating Agreement is "unjust, unreasonable, or unduly discriminatory," can file a complaint under section 206 of the Federal Power Act asking for FERC to make a change.[242]

This process is currently playing out in FERC and the courts. In 2024, PJM made a filing under Federal Power Act Section 206 to transfer transmission planning from the Operating Agreement to the OATT, where the PJM board, rather than the members, would have the authority to amend the regional transmission planning rules through FPA section 205 filings.[243] These changes were jointly filed with amendments to the Consolidated Transmission Owners Agreement filed by PJM's Transmission Owners. FERC rejected both filings,[244] and that decision has been appealed by PJM's Transmission Owners in court.[245]

PJM's regional state committee, the Organization of PJM States, is a formal, incorporated non-profit with a few full-time positions that serves in an advisory role, including regular meetings with PJM's board, but it is one of the only committees not to have complementary Section 205 filing rights.[246] However, with the issuance of Order No. 1920, states were given limited Section 205 filing rights for long-term transmission planning cost allocation that can be agreed to by the Relevant State Entities.[247] In PJM, the PJM Area Relevant State Entities Committee (PARSEC), a part of Organization of PJM States is conducting this process, and is expected to file its Order No. 1920 cost allocation in June 2026.[248]

PJM conducted extensive stakeholder processes around Order No. 1920. PJM held over

240 PJM, Operating Agreement, accessed Jan. 2026, https://agreements.pjm.com/oa/4541.

241 PJM, "Committees & Groups FAQs," accessed Jan. 2026, https://learn.pjm.com/pjm-structure/member-org/committees-groups-faqs/sector-weighted-voting.aspx.

242 PJM, *Open Access Transmission Tariff*, accessed Jan. 2026, https://agreements.pjm.com/oatt/3897.

243 *See generally* Docket No. EL24-119-000; Docket Nos. ER24-2338-000 and ER24-2338-001.

244 PJM TOs' Amendments to the Consolidated Transmission Owners, Docket No. ER24-2336 (Jun. 2024), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240621-5058&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e; Order Rejecting Consolidated Transmission Owners Agreement Amendments and Denying Complaint, 189 FERC ¶ 61,181 (Dec. 2024), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241206-3052&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e.

245 The PJM Transmission Owners submit Petition for Review filed in the US Court of Appeals for the District of Columbia Circuit, Docket No. ER24-2336 (Feb. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250214-5234&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e.

246 Western Resource Advocates, "RTO Governance Models: The Role of States," 12 (Apr. 2019), https://westernenergyboard.org/wp-content/uploads/2019/04/04-17-19-eim-bosr-gardner-rto-governance-models-role-of-states.pdf.

247 Order No. 1920-A at P 651.

248 PJM Area Relevant State Entities Committee (PARSEC), "Charter," OPSI (Oct. 2025), https://opsi.us/wp-content/uploads/2025/10/2025.10.21_Relevant-State-Entities-Committee-Charter.pdf.

36 meetings with the states collectively in a span of 16 months to discuss Order No. 1920 compliance, plus dozens of other meetings with individual states, and 16 public meetings with stakeholders through the Transmission Expansion Advisory Committee (TEAC). PJM integrated some comments in response to the feedback received in these meetings and did obtain the unanimous support of the states for its compliance filing.[249] PJM also holds regular meetings on its RTEP process but, under the current rules outlined above, neither PJM nor the transmission owners are required to respond to any stakeholder comments. PJM's board approves the plan based on staff recommendations.

As discussed in the interregional planning section, PJM does engage with state entities across the northeastern and midwestern U.S. in interregional planning processes although there is currently no mechanism for PJM to act on the results of those processes.

**New York**

New York received a A- on engagement, and is a single-state region, which means there is a more clear relationship between New York state entities and regional planners at NYISO. New York's transmission planning processes are well integrated between NYISO and other New York state agencies, such as formal determination by the NYPSC as to which public policy requirements should be used in NYISO's planning studies.[250] As discussed in the interregional planning section, NYISO, similar to CAISO, has successfully developed and paid for some interregional transmission, though the Northeast State Collaborative on Interregional Transmission suggests there is room to improve the process with in the ISO. The NYISO stakeholder process for transmission planning happens in the Transmission Planning Advisory Subcommittees with a diverse membership that includes consumer interests, but ultimately the Board approves plans. Governance is shared across the NYISO Operating Committee, Business Issues Committee, and Management Committee. The Management Committee takes sector-weighted votes — each sector voting as a bloc — to advance market design and tariff proposals. These votes are advisory to the NYISO Board of Directors, which has final authority to approve proposals for FERC filing. NYISO's planning documents are transparent and include comprehensive information for stakeholders.[251] For regional public policy transmission projects, NYISO utilizes an effective postage stamp cost allocation method where costs are allocated on load ratio basis.[252]

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249 *See* Comments of the PJM Area Relevant State Entities Committee, FERC Docket No. ER26-751-000, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260121-5169&optimized=false&sid=9c4515e6-099b-4b87-afdb-8db7b7132db2.

250 *See* FERC, "An Introductory Guide for Participation in New York ISO Processes" (Sep. 2023), https://www.ferc.gov/media/introductory-guide-participation-new-york-iso-processes.

251 *See* Governance Structure and Practices.

252 *Transmission Cost Allocation Practices* at 19-20.

### New England

New England received an A- on Engagement. The region New England has a robust stakeholder process in ISO-NE, driven by the New England states (*see discussion in the regional planning section*). Stakeholders engage through the Planning Advisory Committee, technical committees, and the Participants Committee, which takes sector-weighted advisory votes. Sectors cast collective votes that signal support or opposition to proposed changes, often with supermajority thresholds for endorsement. Votes guide — but do not bind — the ISO.[253] ISO-NE (or, in specific instances, participating transmission owners) retains Section 205 filing rights and decides whether to file a proposal with FERC.[254] Transmission planning happens in the Planning Advisory Committee, where stakeholders have an advisory to ISO-NE.

New England's RSC is known as the New England States Committee of Electricity (NESCOE). NESCOE exists outside of ISO-NE and has several full-time staff. NESCOE can sponsor proposals in the New England Power Pool and also has complementary Sec. 205 filing rights where if NESCOE secures 60 percent support for an alternative market proposal that differs from what ISO-NE is advancing, ISO-NE must file their proposal at FERC with sufficient detail that FERC can choose between the two filings. This is commonly referred to as the "jump-ball" provision.

ISO-NE continues to move forward with its Asset Condition Reviewer initiative. Costs associated with asset condition projects, which are transmission upgrades identified by transmission owners to address wear and tear, aging, and end-of-life replacement for existing transmission infrastructure, have been rising in recent years, and the ISO is working with stakeholders and transmission owners to develop a role which is intended to improve transparency and review of local transmission projects, but as of now will be advisory only.[255]

ISO-NE does recover network transmission costs based on the entire ISO-NE portfolio, utilizing postage stamp cost recovery, and also filed an updated cost allocation methodology with its LTTP process that allows states to fund individual projects.[256] In addition, as discussed in the regional planning section, ISO-NE created a new cost allocation pathway for states where if a project identified in the LTTP does not have a benefit-to-cost ratio greater than one, one or more states may voluntarily elect to fund the portion of the costs

253 FERC, "An Introductory Guide for Participation in ISO New England Processes" (Apr. 2025), https://www.ferc.gov/introductory-guide-participation-iso-new-england-processes.

254 *See* Governance Structure and Practices.

255 *See generally* ISO-NE, "Asset Condition Reviewer Key Project," accessed Jan. 2026, https://www.iso-ne.com/committees/key-projects/asset-condition-reviewer.

256 *See* ISO-NE, 178 FERC ¶ 61,137 (2022), https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies; See also FERC, "Order Accepting Tariff Revisions, Subject to Condition, and Directing Compliance," Docket No. ER24-1978-000 (Jul. 2024), https://www.iso-ne.com/static-assets/documents/100013/er24-1978-000.pdf.

that do not meet the benefit-to-cost ratio of one.[257]

### 4. Outcomes

The final grade component quantifies real-world "outcomes." This grade — and the metrics associated with it — are based on four different subcomponents. The four subcomponents are planned future regional transmission, planned future interregional transmission, transmission constructed in recent years, and recent historic economic congestion. Given the reliance on quantitative metrics to determine the outcome score, this section is organized differently than the previous sections. Here we discuss each subcomponent individually instead of each region.

The first three subcomponents are compared to regional estimates of transmission needs by 2035 from the DOE's 2023 Needs Study.[258] While the Needs Study is not necessarily a perfect representation of regional and interregional transmission need, we believe it is a reasonable benchmark to guide our evaluation. The Needs Study takes into account regional variation in load, generation, and transmission capacity. This means that some regions need to add much more transmission capacity, relative to other regions, so on a relative basis some regions may be building or planning more, but each grade is determined relative to the region's progress toward the DOE's estimate for that region.

The outcomes component makes up 15% of the final grade. Within the outcomes metric, planned regional and interregional lines are weighted more heavily than congestion or recent transmission construction to tie more closely to the planning outcomes evaluated in the section above. We provide additional details on our methodology for each outcome evaluated in the Appendix. Fig. 25 shows detailed grades for each quantitative subcomponent.

257 *Transmission Cost Allocation Practices* at 3 & 7.

258 U.S. Department of Energy, *National Transmission Needs Study* (2023), https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf ("Needs Study").

**FIGURE 25** Outcome component grades by region

| REGION | PLANNED REGIONAL LINES (30%) | PLANNED INTERREGIONAL LINES (30%) | MILES CONSTRUCTED (20%) | CONGESTION (20%) | OVERALL GRADE |
|---|---|---|---|---|---|
| **California** | A | A | A | D- | A |
| **Northwest** | A | A | D- | F | B+ |
| **Southwest** | B+ | A | F | F | B- |
| **Texas** | C | C | D- | C | C- |
| **Plains** | B+ | A | F | F | B- |
| **Midwest** | C | B+ | F | C | C |
| **Southeast** | D- | F | F | F | F |
| **Mid-Atlantic** | B+ | D- | D- | D- | C- |
| **New York** | A | F | A | B+ | C- |
| **New England** | A | B+ | A | B+ | A |

### OUTCOME | Planned regional transmission

For the first subcomponent, we compared the carrying capacity of planned transmission tracked by Yes Energy (formerly the C Three Group)[259] to the additional transmission capacity needs identified in the Needs Study for the middle scenario group.[260] This subcomponent counts toward 30% of the outcomes grade to provide a more forward looking view and tie more closely to the regional planning grades.

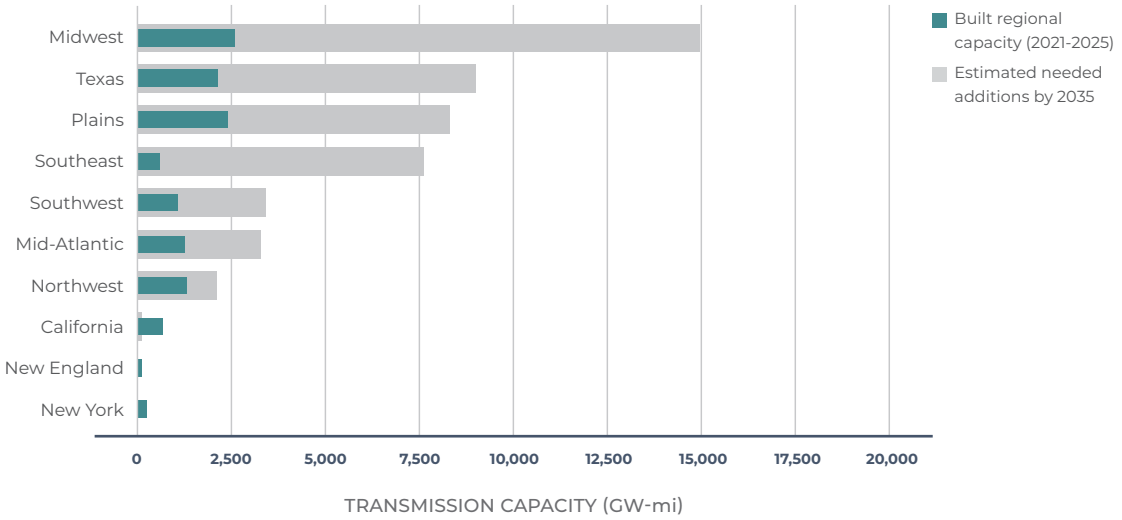
Fig. 26 compares the planned within-region transmission capacity to the DOE's estimated need. Regional transmission is measured in terms of power capacity density (gigawatt-miles).[261]

259 YesEnergy (2025) "Infrastructure Insights: Electric Transmission and Distribution Database," https://www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

260 The middle scenario group in the Needs Study is called the "mid load and high clean energy" group.

261 Gigawatt-miles is a common unit used in U.S. energy planning and modeling to measure required electrical transmission capacity by multiplying the lines power (Gigawatts) by its length (miles) which allows for assessment and comparison of transmission projects and grid expansion plans.

**FIGURE 26** Regional transmission (≥100kV) capacity planned to be operating by 2035 compared to the expected need.




*Data Sources: Yes Energy (2025) & DOE (2023)*

The spread of planned regional transmission lines varies across the regions, but generally regions appear to be planning transmission that would address their projected needs. Three of the ten regions (**California, New England, New York**) are currently planning enough transmission capacity to meet the estimated transmission need identified by the Needs Study.

While it is good to see regions are planning transmission at rates above what was estimated in the Needs Study, these results likely show the shortcomings (and potentially dated results) from the Needs Study, as there is still clearly a demonstrated need for transmission in those regions. As an example, in **New England**, the ISO-NE 2050 Transmission Study demonstrated the need for additional transmission capacity in the region through 2050.[262] Additionally, the transmission capacity targets from the Needs Study used for comparison are likely on the low end of what will be needed given the current load growth paradigm.

Unsurprisingly, the regions that have some of the best planning grades for regional and interregional planning also appear to be planning for a large capacity of transmission additions. For example, both **California** and **New York** have the highest planning component grades and these data show both regions are planning sufficient transmission relative to DOE's estimated need.

262 2050 Transmission Study at 26, 34, 37, and 44.

On the other hand, some regions like the **Midwest** and **Plains** are planning even higher near-term regional and interregional transmission deployment (in absolute terms) than **California** and **New York**, but their need is so much higher that they do not score as highly as regions with both good planning processes and lower needs.

As discussed in the regional planning section, **California**, the **Midwest**, and the **Plains** produce annual regional transmission plans, which in recent years have included significant amounts of new, planned regional transmission. Over the past three transmission plans, CAISO has approved over $18 billion in regional transmission investments. In 2022 and 2024, MISO approved two long-range multi-value transmission portfolios totaling over $30 billion and almost 4,000 miles of 345 kV lines and 1,800 miles of 765 kV lines. While none of this planning has yet to translate to a multi-value portfolio in MISO South, the need is becoming increasingly clear as MISO approved several 500 kV lines in its Southern footprint as a part of MTEP25. In its 2024 ITP, SPP approved its first 765 kV line, and in the 2025 ITP another almost 1000 miles of 765 kV lines were approved for construction, totaling over $16 billion approved.

In the **Mid-Atlantic** recent construction of new high-capacity transmission has been limited, but this will likely change in future Report Cards. Fig. 26 indicates that in recent years PJM has planned and approved significant investments in regional transmission. As discussed in the regional planning section, the 2024 RTEP included a nearly $6 billion investment, with most of the investment going to two 765 kV projects that would extend PJM's extra-high-voltage backbone across West Virginia, Virginia, and Maryland.[263] PJM also presented a preliminary $11.6 billion transmission package for the 2025 RTEP including more than 1,000 miles of 500 kV and 765 kV facilities through a mix of new greenfield lines, upgrades, network reinforcements, and an HVDC line.[264] The preliminary 2025 RTEP lines are not included in the totals in this report as they have not yet been approved. The 2023 RTEP also included some significant 500 kV investments.

In the non-market regions, individual utilities and states are planning and developing significant amounts of transmission that, despite not arising through a regional planning process, will likely have a regional impact. As previously stated, neither NorthernGrid nor WestConnect's transmission planning processes have ever identified any regional or interregional transmission lines for development. Instead, individual utilities and independent/merchant developers are what is primarily contributing to the grades in these two regions.

263 PJM, *RTEP 2024* (Apr. 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

264 PJM, *Reliability Analysis Report: 2025 RTEP Window 1* (Jan. 2026), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-2025-rtep-window-1-reliability-analysis-report.pdf.

In the **Northwest**, PacifiCorp and NV Energy have both undertaken the planning and development of substantial high-voltage transmission projects. PacifiCorp has been working on its Gateway Transmission Projects, which expand over a utility service territory larger than some of the other regions. To plan projects, PacifiCorp utilized proactive generation and load forecasting. Additionally, NV Energy has been developing its Greenlink projects to access new renewable energy zones. Berkshire Hathaway Energy utilities, like PacifiCorp and NV Energy, are unique in their geographic size and scope, and unlike most utilities in the country, can build high-capacity long haul transmission within their footprints — including cost allocation and recovery.

In the **Southwest**, states, utilities, and merchant developers are planning and developing significant amounts of transmission in the region. For example, in Colorado, Xcel is currently constructing the Colorado Power Pathway projects, an approximately $2 billion investment with almost 600 miles of high voltage lines that is expected to help Colorado meet its goals by interconnecting 5.5 GW of resources. The state of Colorado also completed a Transmission Capacity Expansion Study in 2025, based on 2023 legislation, to identify needed transmission capacity expansion in the state by 2045. The study results found an additional $4-$8 billion in transmission was likely needed over the next 20 years to meet state policy and load growth while maintaining reliability.[265] In New Mexico, the Renewable Energy Transmission Authority (NM RETA) is supporting the development of nine high-capacity transmission projects, two of which are operational, and at least one is under construction (*see Fig. 27*). These projects are expected to interconnect most than 15 GW of new generation and represent over 2,200 miles and tens of billions in investment in the state.[266]

265 CETA, "Transmission Capacity Expansion Study for Colorado," accessed Jan. 2026, https://www.cotransmissionauthority.com/transmission-study.

266 NMRETA, "RETA Projects Overview," accessed Jan. 2026, https://nmreta.com/reta-projects/#.

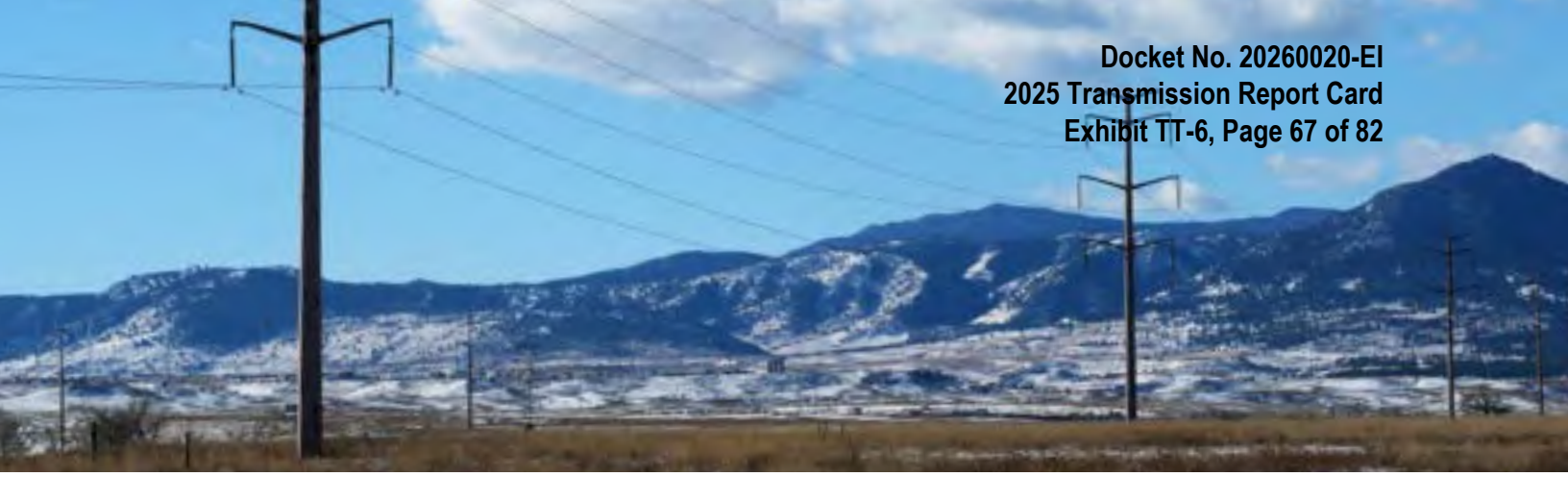


**FIGURE 27** Transmission Projects Supported by New Mexico RETA[267]

In the **Southeast**, as briefly discussed in the regional planning section, individual transmission utilities or groups of utilities are driving plans for significant new high-capacity transmission investment. A majority of the high-capacity transmission investment is in Georgia and will bring online new generation resources to accommodate large load growth and maintain reliability. Georgia Power and the other Georgia utilities, in their ten-year Integrated Transmission System plan have proposed to construct nearly 500 miles of new 500 kV transmission lines, which are intended to be in-service by 2033 (*see Fig. 28*).[268]

Beyond the projects under development in Geogia, there is resistance to building large, high-voltage transmission. One example, discussed above, is Duke's transmission planning process. In both the Multi-Value Strategic Transmission process and Carbon Plan Duke has not identified or selected any greenfield 500 kV transmission projects.

267 *Id.*

268 Georgia *Power, 2025 Integrated Resource Plan*, 120 (Jan. 2025), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf.

**FIGURE 28** Our Grid Future map of planned 500 kV transmission lines included in the Georgia 10-year transmission plan[269]

## OUTCOME | Planned interregional transmission

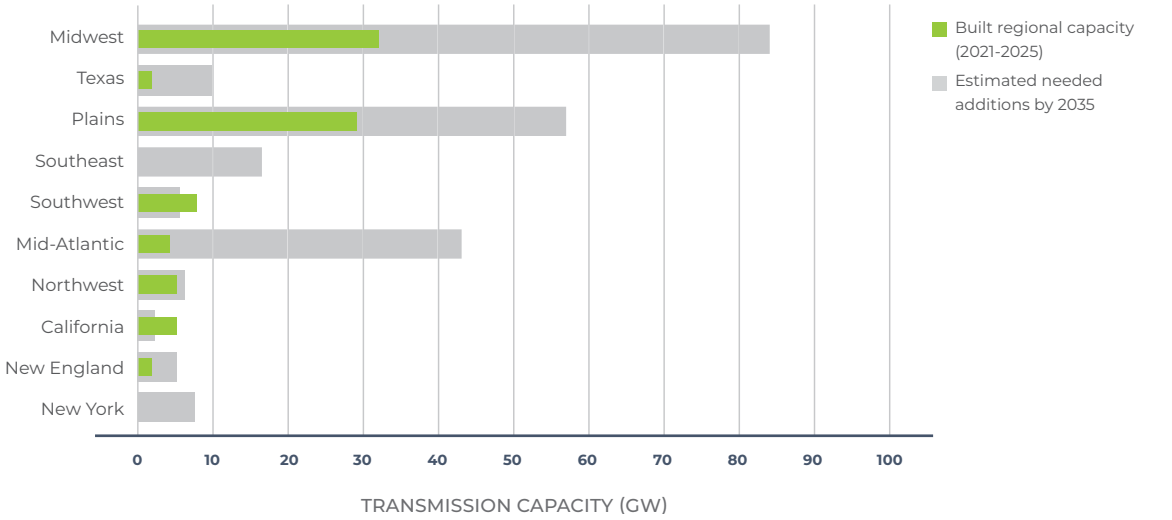
Similar to the planned regional transmission subcomponent, we compared the carrying capacity of planned interregional transmission tracked by Our Grid Future[270] against the additional capacity needs identified in the Needs Study. This subcomponent also makes up 30% of the outcomes grade. Fig. 29 compares the planned interregional transmission capacity in each region to DOE's estimated need. Interregional transmission is measured in terms of power capacity (gigawatt).

For planned interregional transmission the results are a little more mixed, and in most regions independent transmission developers are driving planned interregional capacity. Fig. 29 shows that most regions are likely to fall short of planning for the necessary interregional transmission capacity needed to meet the Needs Study estimates. These results demonstrate the shortcomings of today's ad-hoc interregional transmission planning landscape. While many regions recognize the need for and benefits of interregional transmission and are taking creative steps in its planning, the reality is no formal processes exist to ensure its construction. This is likely contributing to most regions falling short of their projected needs.

269 Abramson, E., Ramsay, E., McFarlane, D., Prorok, M., *Our Grid Future Planned Transmission Projects National Database, Horizon Energy Systems*, December 2025. Available: http://www.ourgridfuture.org ("Our Grid Future").

270 *Id.*

**FIGURE 29** Interregional transmission (≥100kV) capacity planned in each region to be operating by 2035 compared to the expected need.




The Midwest and Plains regions score high for planned interregional transmission. As discussed in the interregional planning section, MISO and SPP continue to move forward with their JTIQ portfolio, despite the uncertainty associated with federal funding. The JTIQ projects are good step forward in developing interregional transmission capacity and will facilitate the connection of 28-53 GW of new generation. The Midwest and Plains regions also have several independent/merchant interregional transmission lines under development, such as Grain Belt Express and SOO Green, that are "shovel-ready" according to ACEG's 2023 Ready-to-Go Transmission Projects report.[271] As we explained above, incorporation of these projects into MISO and SPP's transmission planning processes will improve the development chances for these projects.

**California**, the **Northwest**, and **Southwest** also score high in this subcomponent. WestTEC, despite not having cost allocation, has proven to be a significant west-wide planning exercise, identifying 104 upgrades across the West in the 10-year plan. These upgrades consist of newly identified projects as well as some that have been under development by utilities or transmission developers. Independent developers are planning some significant interregional transmission projects in the West. For example, the North Plains Connector transmission facility (developed by Grid United, Allete, and Pattern) is one of several under development transmission facilities that would connect the Eastern and Western Interconnects. Additionally, several new transmission lines are being developed

271 Zimmerman, Z., et al., *Ready-to-go transmission projects, ACEG and Grid Strategies*, 4 (Sep. 2023) https://cleanenergygrid.org/wp-content/uploads/2023/09/ACEG_Transmission-Projects-Ready-To-Go_September-2023.pdf.

by independent developers to better interconnect the Northwest with its neighbors, including the Cascade Renewable Transmission Project (PowerBridge, Sun2o Partners, and NextEra Energy Transmission) and the Western Bounty Transmission System (Engie North America).[272]

Independent/merchant development between **Texas** its neighbors has boosted the region's grade for planned interregional transmission capacity, despite ERCOT having no interregional planning process. Independent/merchant transmission developers, in particular Pattern and Grid United, are developing interregional transmission projects that would increase transfer capacity between Texas and the Eastern and Western Interconnects.[273]

Notably, planned transmission is not always constructed. So, the inclusion of high-capacity lines in planning does not guarantee that the projects will get built or the anticipated future need will be met. This caveat is potentially more applicable to interregional transmission, as many of the planned interregional transmission lines are being developed by independent merchant developers and may not have a clear path to regional approval or cost recovery. Additionally, many of the lines discussed in this report are substantial multi-state projects that would benefit from additional streamlining in federal siting and permitting processes.

### OUTCOME | Transmission Constructed

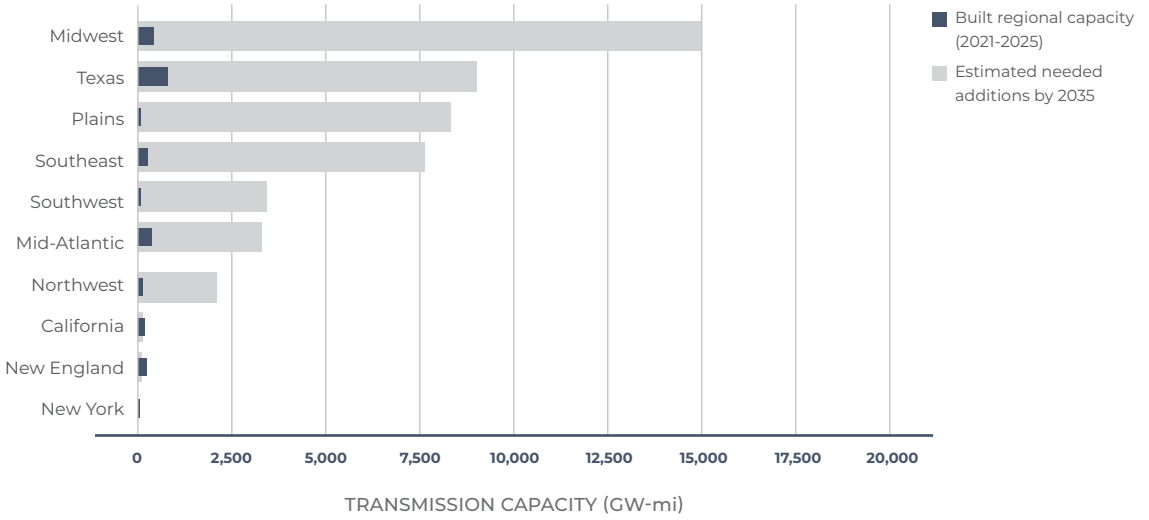
The third subcomponent evaluates miles of recently constructed high-capacity transmission lines (100 kV and up). Using data from Yes Energy, our analysis compares the total capacity of transmission energized between 2021 and 2025 to the estimated transmission capacity addition needs identified for each region from the DOE's 2023 Needs Study.[274] Fig. 30 shows the total new transmission constructed in each region compared to the estimated regional need in terms of power capacity and length as measured in gigawatt-miles. This subcomponent counts toward 15% of the outcomes grade.

272 See "Cascade Renewable Transmission Project," accessed Jan. 2026, https://www.cascaderenewable.com/; See also "Western Bounty Transmission System," accessed Jan. 2026, https://www.engie-na.com/wp-content/uploads/Flyer_Western_Bounty_Transmission_System.pdf.

273 *See* Southern Spirit and Pattern.

274 *See* DOE Needs Study.

**FIGURE 30** Transmission (≥100kV) capacity constructed in each region between 2021 and 2025 compared to the 2035 expected need.




*Data Sources: Yes Energy (2025) & DOE (2023)*

As with the first edition of this Report Card, most regions are still not constructing new high-capacity transmission at the rate required to meet anticipated need. A few regions, however, have constructed a significant number of new miles of high-capacity transmission. Sometimes those regional grades are boosted by a singular, large project that spent numerous years in development and has finally been constructed.

Almost 900 miles of new high-voltage transmission were constructed nationwide in 2024. These miles can be attributed to just a handful of high-capacity projects, most with long development timelines. For example, the 125-mile Ten West Link project, which was energized in 2024, was first approved by **California** in 2013. And the 102-mile Cardinal-Hickory Creek project was approved in the **Midwest** in 2011 as part of MISO's Multi-Value Projects portfolio. Lastly, the Energy Gateway South line in the **Northwest** — originally announced by PacifiCorp in 2007 and partially completed in 2015 — was finally energized in 2024 after the last segment of construction was completed.[275]

The regional construction targets used here from the Needs Study reflect median outcomes in a range for the mid-scenario (mid-load growth and mid-clean energy deployment). These regional targets, in all likelihood, are at the low end of needed future transmission given the current high-load growth paradigm we find ourselves in. Some regions

275 ACEG and Grid Strategies, *Fewer New Miles: Strategic industries held back by slow pace of transmission Rev. 1*, 6-10 (Jul. 2025), https://cleanenergygrid.org/wp-content/uploads/2025/07/ACEG_Grid-Strategies_Fewer-New-Miles-2025_Rev-1.pdf.

— **New York, New England**, and **California** — are constructing transmission in excess of these targets, proactively preparing their regions to keep up with high load growth. For example, in 2023, New York completed its Public Policy Transmission Segments A and B, also known as the Central East Energy Connect and New York Energy Solution, adding approximately 150 miles of 345 kV transmission line to help New York meet its state policy goals.[276]

While not a part of the grade because of lack of data, one other important note on recent high-capacity construction is the challenges related to construction. Regions do have variance analyses for projects that may have significant cost overruns.[277] Order No. 1920 also included additional cost containment measures,[278] but there can be limited transparency on the underlying causes of longer construction timelines. One observation is that performance appears to vary by transmission owner even within regions, and it is not clear whether there are good reasons for variation in performance across transmission owners, or whether certain transmission owners need to adopt different practices.

### OUTCOME | Congestion

The final subcomponent, congestion, reflects a representative snapshot of each region's available transmission system capacity, which, in turn, informs consumer impacts as greater congestion equates to higher energy delivery costs and limits the opportunity for desired generation resources to add power to the grid. Generally, lower congestion is associated with adequate capacity on a high-capacity transmission system to meet today's load and generation. However, a good grade does not necessarily mean the region is prepared for future needed capacity additions. As with the previous metrics, robust, proactive regional transmission planning occurring in a region would increase transmission capacity and could help reduce congestion. This subcomponent counts toward 15% of the total outcomes grade for a region.

For the evaluation, economic congestion was adjusted for the annual load in each region, so the final congestion number is the total dollars of congestion per total MWh of load in the region (*see Fig. 31*). Regions scored high in the congestion category if their absolute annual congestion for years 2021, 2023, and 2024 were low and trending downwards. We

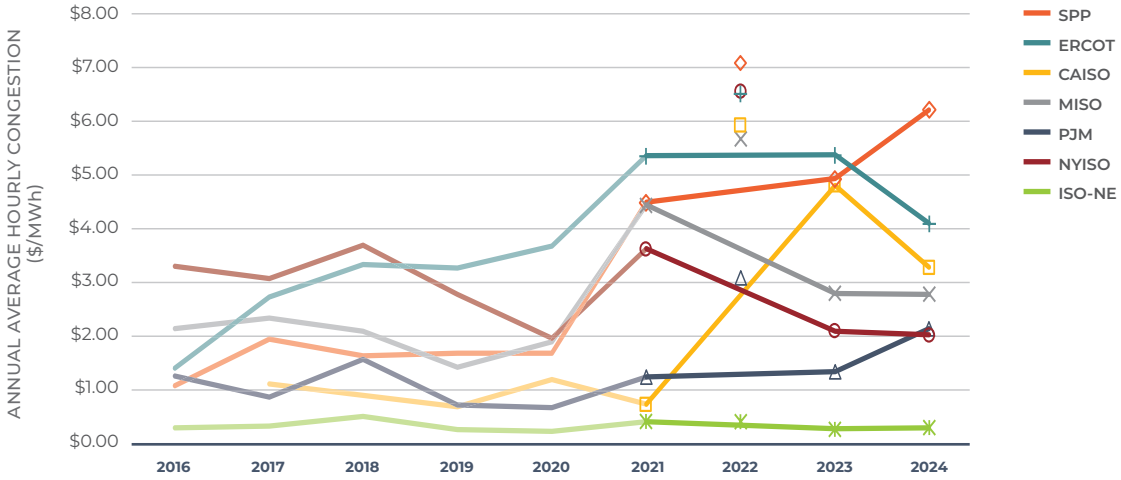
276 *See* New York Governor Kathy Hochul, "Governor Hochul Announces Completion of Central East Energy Connect Transmission Line" (Dec. 2023), https://www.governor.ny.gov/news/governor-hochul-announces-completion-central-east-energy-connect-transmission-line; *See also* New York Transco, "New York Transco Announces Energization of New York Energy Solution Clean Energy Transmission Project" (Aug. 2023), https://static1.squarespace.com/static/5d31dc252528ec000193dbb3/t/64dd36df8ebe51596be41849/1692219103967/NYES+News+Release.8.16.23_updated.pdf.

277 *See* Wilson, J., et al., *Independent Transmission Construction Monitor* (Nov. 2024), https://gridstrategiesllc.com/wp-content/uploads/Independent-Construction-Monitor-Grid-Strategies-Nov-2024.pdf.

278 *Id.*

omitted congestion data across all regions for year 2022 as several variables — Russia's invasion of Ukraine, significant winter storms — inflated congestion pricing across the entire U.S. that year. Even with the omission of 2022, congestion continues to rise across many regions. Congestion data was sourced from Annual Market Monitor Reports for each region, and a summary of sources can be found in Grid Strategies' *Transmission Congestion for 2024* report.[279]

**FIGURE 31** Historic annual load-weighted congestion prices in each region. With the omission of year 2022, the most recent three years (2021, 2023, 2024) are highlighted.




Across the country, several regions, the **Midwest**, **New England**, and **New York**, have seen a downward trend in load-weighted congestion since 2021 (excluding 2022 as discussed above). **Texas** has also seen load weighted congestion trend downward, though the region has the second highest overall average level of congestion over the past three years. **California** and the **Plains** have seen some of the largest jumps in load weighted congestion since 2021, which is reflected in the highest and third highest average load-weighted congestion respectively. The **Mid-Atlantic** saw a slight upward trend in congestion over the past three years, but their average load weighted congestion has stayed relatively constant since 2016.

There is little transparency or congestion data available in the non-organized markets in the **Northwest**, **Southwest**, and **Southeast**, so grades were assigned as zeros. Given that on average congestion across the country in the 2020s is rising compared to pre-2020, we believe it is safe to assume similar trends also apply in the three non-organized market regions.

279 *See*, Shreve, N., et al., *Transmission Congestion for 2024, Grid Strategies* (October 2025), https://gridstrategiesllc.com/wp-content/uploads/GS_Transmission-Congestion-for-2024.pdf ("Transmission Congestion for 2024").

# Conclusion

The 2025 Report Card shows marked improvement in regional and interregional planning processes, engagement, and real-world transmission development outcomes across ten regions. Grades differ across regions based on actions by the regional planning entity as well as state and individual utility actions within each footprint. Although region-specific recommendations are beyond the scope of this report, we provide some basic guidance on what "good" transmission planning and development entails across the four scored categories; additional detail is provided in the methodology section.

Across both regional and interregional planning, regions can improve by implementing six core elements:

1. Proactive, 20-year planning for generation and load;
2. Scenario-based planning that extends beyond sensitivities and includes extreme weather beyond a 1-in-10 standard;
3. Multi-value planning across needs and benefits;

4. A portfolio approach;
5. Consideration of all business models and Advanced Transmission Technologies; and
6. Integration with related planning processes (including resource adequacy and regional/interregional efforts).

Because regional and interregional planning are the most heavily weighted categories, improvements here will have the greatest impact on overall grades.

For engagement, regions can improve by strengthening transparency and formal stakeholder representation, ensuring meaningful state representation and incorporation of state policies, and adopting cost allocation approaches that enable both regional and interregional projects. For outcomes, improvement can be achieved by reducing congestion and planning for and constructing transmission development at a pace consistent with the capacity goals articulated in DOE's Needs Study.

No metric is perfect, and some subjectivity is unavoidable. Even so, the grades are intended as a benchmark against best practices, and we hope this report catalyzes an urgent conversation among policymakers, planners, and stakeholders about the improvements needed in transmission planning and development to ensure the United States has the infrastructure required to meet evolving reliability and affordability needs while meeting growing energy demands.

# Appendix
## Methodology

Similar to the first Report Card, this third edition relies on both qualitative and quantitative metrics.[280] The qualitative metrics generally evaluate planning best practices. The quantitative metrics are based on real-world outcomes related to constructing large-scale transmission ("putting steel in the ground") to determine whether a region's planning processes are delivering results.

This Report Card is intended to provide an update on regional transmission planning and initiate a constructive conversation around the state of interregional transmission planning practices across the U.S. given the numerous studies highlighting the need and value of interregional transmission. The Report Card discusses differences in planning processes and the impact that those differences are having on real-world outcomes.

The grades are assigned based on objective measures, with a stated basis for each one, so that others may try to replicate the grading. Because there can be subjectivity in the weighting given to various factors and the interpretation of data, reasonable people can disagree on individual grades or grading scales chosen. Additionally, individual metrics can be interpreted differently and may not represent a region's comprehensive performance. While no grade is sacrosanct, we feel a region's overall grade reflects a fair representation of how each region performs compared to well-established best practices.

For this Report Card, we evaluated ten regions total. The regions generally follow FERC Order No. 1000 planning borders and ERCOT (*see* Fig. A-1). For the Southeast we combined SERTP, SCRTP, and FRCC. It is important to note that in some regions — particularly those in the non-RTO areas — regional and interregional transmission planning often occurs more at the utility-level. While our grades generally reflect the actions of the regional planning entities, we do also credit regions for best practices occurring at the state or utility level, which can materially influence outcomes. Where these actions affect a grade, we note that in the report.

For the assessment of this metric, practices were evaluated on a scale from 0 to 5. The following sections provide further details on each metric being used to evaluate whether

280 The second edition, released in 2024, functioned as a progress updated and did not include updated grades.

regions incorporate planning best practices in their transmission planning processes and how that impacts real-world outcomes.

**FIGURE A-1** FERC Order 1000 Planning Regions[281]

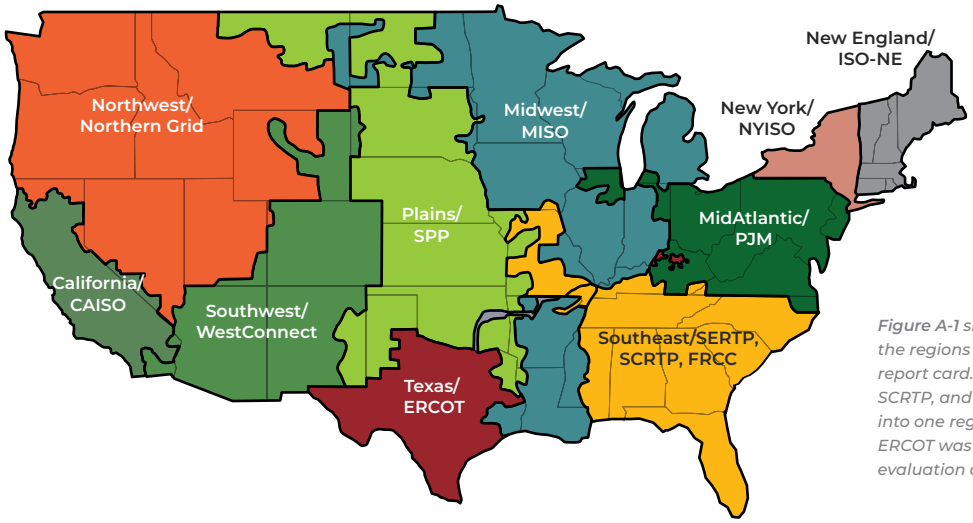



*Figure A-1 shows the borders of the regions used for grading in the report card. In the Southeast, SERTP, SCRTP, and FRCC were combined into one region, the Southeast. ERCOT was also included in the evaluation and is indicated in gray.*

## Regional Transmission

For the regional transmission planning grade, we reviewed the most recent planning cycle, tariff provisions, and any relevant state or utility actions. Our tests focus on whether the region uses transparent inputs, evaluates a wide range of futures, and selects portfolios that minimize total system cost while maintaining reliability.

The grade for regional transmission planning reflects performance across established best practices. This metric accounts for 35% of the overall Report Card. The weighting is lower than in the initial Report Card because this edition places added emphasis on interregional transmission. However, regional planning remains a major contributor to the final grade because proactive and holistic planning signals a region's ability to deliver the lowest-cost power system for consumers while reliably addressing load growth.

We assessed whether each region's methods align with the best practices listed below. The regional planning grade assesses whether a region's planning processes are incorporating best practices. As discussed elsewhere, these practices broadly align with requirements in Order No. 1920.

281 FERC, "Regions Map Printable Version Order No. 1000," November 9, 2021, https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

Each best practice is scored on a 0–5 scale. Five means that best industry practices are used consistently. Three indicates partial adoption of best practices with gaps in documentation or scope. Zero indicates the practice is absent or only nominally present.

The list below summarizes the criteria used to evaluate whether regions incorporate these best practices into their transmission planning processes.

1. Proactive planning for future generation and load
    a. Forecast the likely future resource mix
    b. Reflect customer and utility commitments that affect supply and demand
    c. Estimate load levels and profiles over the investment life
        i. Include end-use electrification
        ii. Include extreme weather effects
    d. Account for expected resource retirements
2. Scenario based planning
    a. Evaluate a broad set of plausible futures (i.e. beyond singular power flow models and NERC reliability cases)
    b. Include extreme weather scenarios
    c. Favor a least-regrets outcome across scenarios
3. Multi-value planning
    a. Consider projects that resolve multiple categories of need (i.e. reliability and economic)
    b. Quantify a set of benefits equal to or better than the benefits required in Order No. 1920
4. Utilization of a portfolio approach
    a. Evaluate how candidate facilities interact and optimize the system
5. Consideration of all transmission business models (i.e. merchant developer and non-developer proposals) and Advanced Transmission Technologies
    a. Evaluate benefits from reasonable non-incumbent developer transmission plans
    b. Incorporate Grid Enhancing Technologies (e.g., Dynamic Line Ratings, Advanced Power Flow Controls, Topology Optimization) and High Performance Conductors (e.g., carbon fiber and composite conductors and superconductors)
6. Integrated Planning
    a. Evaluate if the regional planning process, including inputs, assumptions, and outputs is aligned with other planning processes (e.g., resource adequacy assessments)

### Interregional Transmission

Similar to regional transmission planning, we reviewed the most recent planning cycle (if any), tariff provisions, and any relevant state or utility actions for the interregional transmission planning component. Our evaluation is based on performance across best practices similar to the regional planning metric.

Interregional transmission planning also accounts for 35% of the overall grade for the Report Card. Each best practice is scored on a 0–5 scale. With one exception, we used identical criteria to those outlined in the regional transmission planning methodology section above. We also considered if each region's interregional planning processes are aligned with the interregional planning processes, schedule, input assumptions, and benefits of their neighbors.

### Engagement

Good stakeholder and state engagement along with balanced governance improves the quality of plans and the durability of decisions. We evaluate representation, transparency, and opportunities for stakeholders to shape assumptions and alternatives.

Engagement accounts for 15% of the overall grade. We evaluate whether a region's structure includes meaningful roles for load and generation customers, representation for non-utility companies and transmission developers, and participation from non-governmental organizations (NGOs) and consumers. Diverse participation improves innovation, transparency, and accountability in transmission planning. State participation also increases the likelihood of broad support for regional plans and alignment with policy objectives.

Engagement also includes evaluation of cost allocation for both regional and interregional transmission projects. If the region has a broad-based cost allocation methodology that quantifies the benefits defined above and allows for the selection and construction of regional or interregional projects, the region scores higher.

Each best practice is scored on a 0–5 scale. Below are additional details on the metrics used to evaluate engagement in regional transmission planning processes.

1. Are non-utility entities and/or transmission companies represented?
2. Are states or their policies represented in any formal way?
3. Are consumers and NGOs represented in the voting?
4. Does the region have effective cost allocation for the development of regional and interregional projects

## Outcomes

This report includes four quantitative metrics that are 15% of the overall grade and evaluate real-world outcomes related to planning and constructing large-scale transmission to determine whether a region's planning processes are delivering results. The outcomes metric includes four subcomponents which are weighted to reflect the connection between regional and interregional planning. The four subcomponents are a) regional transmission constructed (20%), b) planned regional transmission (30%), c) planned interregional transmission (30%), and d) congestion (20%). The methodology for each section is described in detail below.

### Recently Constructed Transmission

The first quantitative metric evaluated was recently built transmission lines. Grades compare the annual average miles constructed over the past three years, from Yes Energy data[282] with the annual average transmission need for each region from the DOE's 2023 Transmission Needs Study.[283] Below are the steps we took to arrive at the grades.

i. **Data sources:** We evaluate new high-capacity transmission placed in service during 2021 through 2024 using data from Yes Energy. The carrying capacity of transmission lines are from MISO's Transmission Cost Estimation Guide.[284] Target transmission capacity addition rates for each region are the estimates from DOE's Needs Study of the gigawatt-miles required by 2035 to meet new electricity demand. The comparison values chosen are the median results of the middle scenario from the DOE Needs Study.

ii. **Evaluation:** The power capacity (in GW-miles) of recently constructed lines was calculated by multiplying the carrying capacity of any facility (in mega-volt amperes) energized between 2021 and 2025 by the number of circuits and by the facility length (in miles). If this facility was a reconductored or upgraded line and not a greenfield project, then the final capacity was derated to only 20% of this calculation to represent a marginal improvement of carrying capacity to the overall system. When the developer-identified carrying capacity of the line was not available, we estimated the carrying capacity of each voltage classification using the per circuit power rating of each voltage class from MISO's MTEP Transmission

282 Data from Yes Energy is summarized in FERC's monthly "Energy Infrastructure Updates." See FERC, Staff Reports and Papers, accessed October 2025, https://www.ferc.gov/staff-reports-and-papers.

283 DOE, *National Transmission Needs Study*, at 123-124 (Oct. 2023), https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

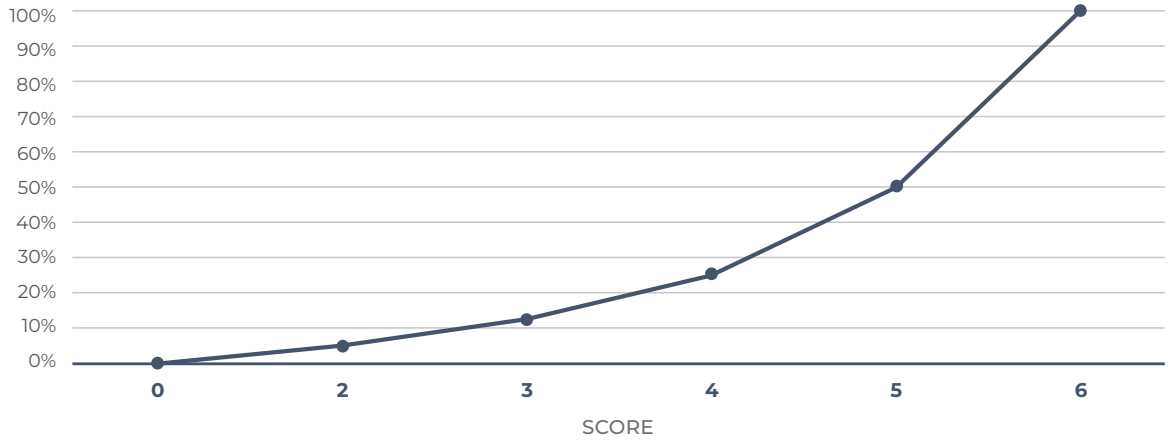
284 MISO, *Transmission Cost Estimation Guide for MTEP24*, 33 (May 2024), https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf.

Cost Estimation Guide.[285] The sum of all power capacities in each region were then compared to the anticipated 2035 regional need from the DOE Needs Study.

iii. **Scoring:** Each region was scored on a 0–5 scale based on the percentage of regional needs from DOE Needs Study that were met from the recently added projects. A score of zero reflects negligible additions. One reflects progress below 5% of the benchmark need. Two reflects progress between 5-12.5%. Three reflects progress between 12.5%-25%. Four reflects progress between 25%-50%. Five reflects progress above 50%. These scores are shown in Figure A-2.

**FIGURE A-2** **Numeric score assigned to outcomes**

*Numeric score assigned based on percentage of 2035 needs met in each category*




**Planned regional and interregional transmission**

The second and third quantitative metrics we evaluated were planned regional and interregional transmission projects. For planned regional projects, the methodology is identical to that described in the recently constructed lines, only applied for transmission facilities that are in development instead of those already energized. We included all active U.S. projects of at least 100kV nominal voltage within the Yes Energy database with a target in service date of 2035 or earlier, regardless of whether they are in advanced, early, or conceptual development stages.

For planned interregional transmission lines, which we defined as planned transmission lines between the Order No. 1000 planning regions, the methodology is slightly different. Following the steps outlined for the constructed regional transmission, we used the

285 *Id.*, "Table 3.1-5" at 33.

same methodology to calculate an interregional grade. Data used for interregional transmission came from Our Grid Future[286] as we noticed gaps in the interregional data available in other sources. To align with the DOE Needs Study, we calculated carrying capacity in GW instead of calculating carrying capacity of planned transmission in GW-miles. The same carrying capacities for voltage classes were used, but without regard for transmission facility length.

### Congestion

The final metric, congestion, reflects a representative snapshot of each region's available transmission system capacity which, in turn, informs consumer impacts as greater congestion equates to higher energy delivery costs and limits the opportunity for desired generation resources to add power to the grid.

Generally, lower economic congestion is associated with adequate capacity on the high-capacity transmission system to meet each day's load and generation. However, a good grade does not necessarily mean the region is prepared for future needed capacity additions. As with the previous metrics, robust, proactive regional transmission planning would increase transmission capacity and help reduce congestion.

Congestion was normalized by annual load in each region, representing total dollars of congestion per total MWh of load in the region. The congestion data was sourced from Annual Market Monitor Reports for each region, and a summary of sources can be found in a recently released Grid Strategies report.[287]

Each region was scored on a 0–5 scale. The grade for each region is a combination of the average load weighted congestion (3 out of 5 points) and the congestion trend (2 out of 5 points) for the last three years (2021-2024), excluding 2022 because much of the increase in transmission congestion that year was due to extreme weather and gas price spikes caused by Russia invading Ukraine. For the average load weighted congestion, 0 reflects an average load weighted congestion higher than $5 per MWh and an upward trend in congestion. One reflects an average load weighted congestion between $3 and $5 per MWh and no change in congestion trends. Two reflects a downward trend in congestion and load weighted congestion between $1 and $3 per MWh. Three reflects load weighted congestion less than $1 per MWh. A four or five reflects a combination of a constant or downward trend in congestion and an average load weighted congestion between $1 and $3 per MWh or $3 and $5 per MWh.

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286 Our Grid Future.
287 Transmission Congestion for 2024.

U.S. DEPARTMENT OF ENERGY

# National Transmission Needs Study

**October 2023**

**United States Department of Energy**
**Washington, DC 20585**

# Executive Summary

A robust transmission system is critical to the Nation's economic, energy, and national security. The electric grid continues to face challenges that are due to aging infrastructure and insufficient transmission capacity. The U.S. Department of Energy undertakes this National Transmission Needs Study (Needs Study) pursuant to Section 216(a)(1) of the Federal Power Act (FPA)[1] to identify transmission needs that are currently harming consumers or expected to do so in the future and that could be alleviated by transmission solutions. Findings from this Needs Study will inform the Department of Energy as it coordinates the use of its authorities and funding that relate to electric transmission, including implementing the many grid resilience and technology investment provisions of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. The Needs Study is an assessment of publicly available data and more than 120 recently published reports that consider current and anticipated future needs given a range of electricity demand, public policy, and market conditions. All findings of needs are presented by geographic area (*see* Figure ES-1) where appropriate.

The purpose of this study is not to prescribe particular solutions to issues faced by the Nation's power sector. Rather, it assesses need in order for industry and the public to suggest the best possible solutions for addressing them in a timely manner. As used in this study, an electric transmission need refers to the existence of present or expected electric transmission capacity constraints or congestion in a geographic area, consistent with FPA Section 216(a)(1). Geographic areas where a transmission need exists would benefit from an upgraded, uprated, or new transmission facility—including alternative transmission solutions—to improve the reliability and resilience of the power system; alleviate transmission congestion and unscheduled flows; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to meet demand; and/or meet projected future generation, electricity demand, or reliability requirements.

[1] "Not later than 1 year after August 8, 2005, and every 3 years thereafter, the Secretary of Energy (referred to in this section as the 'Secretary'), in consultation with affected States and Indian Tribes, shall conduct a study of electric transmission capacity constraints and congestion" 16 U.S.C. 824p(a)(1).

*Source: National Renewable Energy Laboratory.*

***Figure ES-1. Geographic regions used in the Needs Study.***

**Historical Transmission Investments Declined in the Second Half of the Last Decade, and Were Focused Primarily on Incremental Reliability Needs**

A review of historical transmission system data from 2011 to 2020 provides insight into key indicators that demonstrate the need for increased transmission capacity. Annual average spending on transmission was between $0.17 (Florida) and $5.90 (New England) per megawatt-hour (MWh) of annual load in each region between 2011 and 2020. These investments resulted in annual average builds between 5 (Alaska) and 800 circuit-miles (Texas) of new or upgraded transmission. Many of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015 in several regions. Addressing incremental reliability needs remained the main driver of all transmission investments.[2] Figure ES-2 shows the circuit-miles of all new or upgraded transmission energized in each region between 2011 and 2020 by motivating driver. In all, 3,300 circuit-miles of new or upgraded transmission were energized annually, on average, within all regions of the United States. Only 70 circuit-miles of interregional transmission were energized between the regions on average each year.

[2] As discussed in Section IV.a, the historical transmission system dataset used in this review defines a transmission project motivated by a "reliability" need driver as one that meets a need to improve reliability concerns of the local or regional electric grid, as defined by the relevant state, regional reliability entity, or the North American Electric Reliability Cooperation standards.

*Source: Data from MAPSearch Transmission Database (2023).*

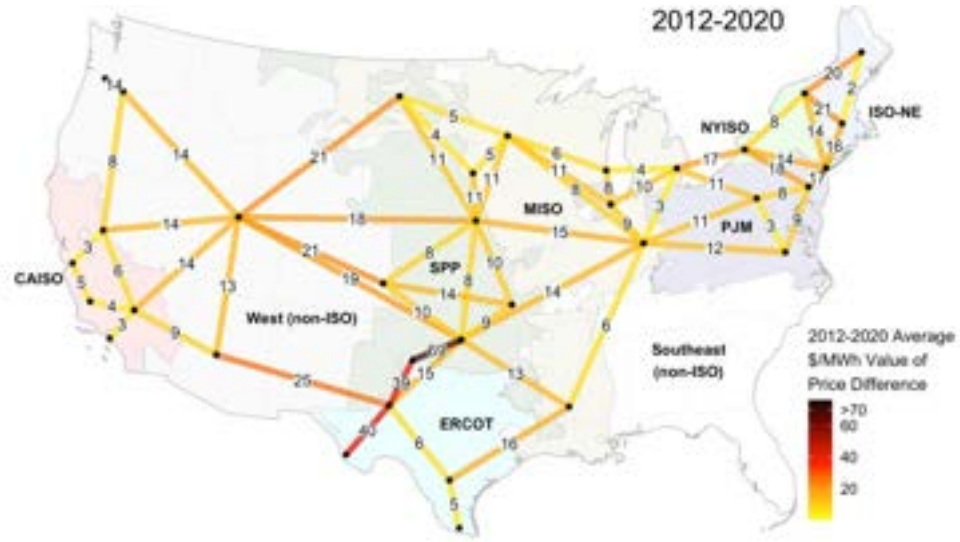
*Note: The scale of circuit-miles shown on the y-axis changes with each row of charts, as indicated by the circle, obscuring the scale of projects relative to other regions. All interregional projects are grouped together and shown separately from regional projects.*

***Figure ES-2. Regional circuit-miles of new or upgraded transmission lines (≥100 kV) energized in each year by project driver.***

**Persistently High Wholesale Market Price Differences Between and Within Regions Show That Several Regions Are Experiencing Transmission Congestion and Constraints Today**

Wholesale market price differentials between and within the regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTOs/ISOs) also provide insight into where transmission congestion currently exists. Several regions of the country—notably portions of the Plains, Midwest, Mid-Atlantic, New York, and California—have experienced persistently high wholesale electricity prices over the past 3–5 years. Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission congestion value coming from only 5% of hours. The price differentials between two locations on the power grid shows where transmission constraints are preventing lower-priced energy from reaching these high-priced areas and quantifies the congestion relief value of building transmission between the locations. Figure ES-3 shows the average difference in hourly prices between several locations on the grid. The highest congestion relief value is found across the Eastern, Western, and Texas Interconnections and between New England and New York. But congestion relief would provide significant value within and between other regions as well.

As shown in Figure ES-3 below, there are gaps outside of RTO/ISO regions where information regarding the economic value of congestion is not available; these gaps do not reflect the absence of transmission needs but rather the absence of market data with which to calculate price differentials. Transmission system operators in non-RTO/ISO regions do not use a market-based approach to determine the economic value of transmission congestion. Instead, they often use the availability of transmission service and the need to deny user requests for transmission service as a measure of congestion. In Southeastern regions not served by RTOs/ISOs, transmission system operators use Transmission Loading Relief administrative procedures to curtail or reduce agreed-upon transmission services. The incidence of those curtailments provides one measure of congestion. But such measures of congestion do not provide information on the value of foregone transmission service, nor do they provide insight into where *future* congestion might arise.




*Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).*

***Figure ES-3. Average hourly difference in price between selected hub zones within and across regions between 2012 and 2020.***

**Assessment of Published Studies Reveals Current and Future Drivers of Transmission Needs—and the Benefits to Consumers of Addressing Those Needs—in Every Region**

As part of this Needs Study, DOE undertook a review of recently published power systems studies from a broad cross-section of subject matter experts and industry sectors. This review captures the historic and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission system as assessed by a variety of entities, including the U.S. Government, national laboratories, academic institutions, consultants, and a range of industry participants. In examining findings of transmission need from existing studies, the Department can identify common drivers of transmission need, as well as capture unique geographic differences that drive the need for transmission across the United States. In addition, this approach allows the Department to consider transmission needs anticipated to arise under a range of future electricity demand, public policy, and market conditions.

Across the literature, the main determinants of need for transmission expansion identified include grid reliability and resilience, congestion relief, new generation resource interconnection, and load growth accommodation. Overall, findings assessed in this Needs Study demonstrate transmission capacity expansion can serve to enhance system stability through improved operational flexibility, resource sharing, and frequency response. Reliability and resilience needs are expected to require additional transmission as economic factors and clean energy targets prompt higher levels of variable energy resource integration and as extreme weather events nationwide continue to increase in frequency and intensity. Study findings also indicate that interregional and cross-interconnection transmission investments will improve system resilience and alleviate resource adequacy concerns by enabling increased access to diverse generation resources across different climatic zones. Throughout the country over the next decade and beyond, increasing consumer demands, electric utility decarbonization targets, and federal and state policy are expected to drive changes in

electricity supply and change the way electricity is used, including by increasing electrification of end-use technologies. These changes will put additional burden on the existing transmission system and create significant need for additional transmission investment. In addition, study findings indicate that additional transmission deployment in nearly all regions, along with other alternative transmission solutions, can help alleviate transmission system congestion. Equitable investments made with a lens of energy justice in areas with higher cumulative burden may mitigate existing harms and increase benefits to frontline communities facing high energy burden, longer-duration outages, and higher levels of environmental hazards.

The studies assessed here also highlight that transmission deployment faces siting and permitting challenges. Alternative transmission solutions (e.g., energy storage, grid-enhancing technologies, and advanced conductors and cables) and the strategic siting of generation and transmission may help avoid these challenges in some, but not all, cases. These techniques are particularly useful to defer new transmission investments by several years or in cases when the carrying capacity of existing transmission must be increased. But such solutions will almost certainly fail to meet the full scope of transmission needs identified by this Needs Study.

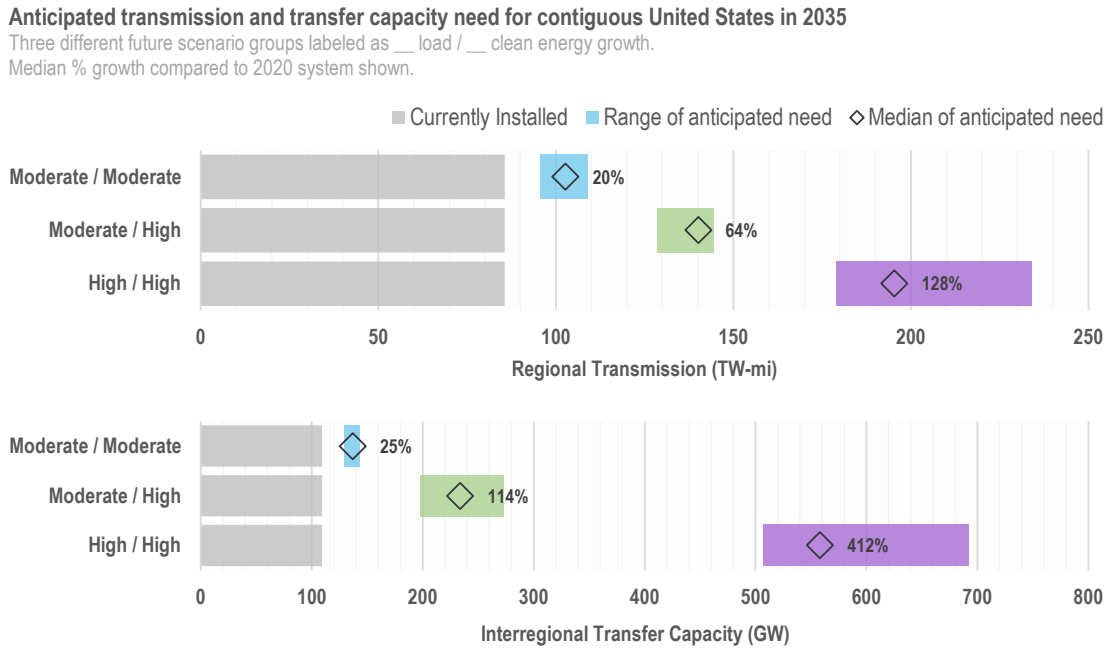
**Capacity Expansion Studies Demonstrate That Significant Future Transmission Investments are Necessary to Address Anticipated Needs Under a Wide Variety of Future Scenarios**

In the Infrastructure Investment and Jobs Act of 2021, Congress expanded the scope of this Needs Study by requiring DOE to assess not just existing transmission needs, but also expected future transmission needs. Anticipated future transmission need can only be estimated using assumptions about the power sector of the future. Several national laboratory and academic researchers have performed nationwide capacity expansion studies to co-optimize generation and transmission growth given different future scenarios. The transmission builds resulting from six recently published capacity expansion studies were considered to identify future regional transmission and interregional transfer capacity needs. Because future transmission need can only be estimated and are uncertain, ranges of anticipated need from the study results are presented.

Analysis of these capacity expansion models across a range of potential system futures shows significant future need for transmission both within regions and between them (i.e., interregional transmission). With respect to regional needs, Figure ES-4 (top) shows the range of within-region transmission deployment needed for the contiguous United States for three different scenario groups in 2035. Capacity expansion studies show within-region transmission deployment needs to increase by 20% (median result) to meet a future with moderate load and clean energy growth in 2035. This within-region transmission need increases to 64% (median result) to meet a future with high clean energy growth in 2035, which most closely represents the anticipated future power sector given all existing state and federal legislation. This need rises again to 128%—a more than doubling of the current system—to meet a future with high load growth in 2035.

With respect to interregional transmission need, Figure ES-4 (bottom) shows the range of interregional transfer capacity need for the contiguous United States for three different scenario groups in 2035. Like regional transmission deployment, interregional transfer capacity

must grow as generation and load changes in the future. Median capacity expansion results show interregional transfer capacity must grow by 25% to meet future moderate load and clean energy growth, by 114% to meet moderate load and high clean energy growth, and by 412% to meet high load growth futures by 2035. The latter two needs represent a doubling and quintupling of the nation's current interregional transfer capacity, respectively.




*Note: Median and interquartile range of within-region transmission and interregional transfer results for six different recent capacity expansion models shown. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a). Considered scenarios are categorized into groups by their future load and clean energy growth, respectively (e.g., **High** load/**High** clean energy growth).*

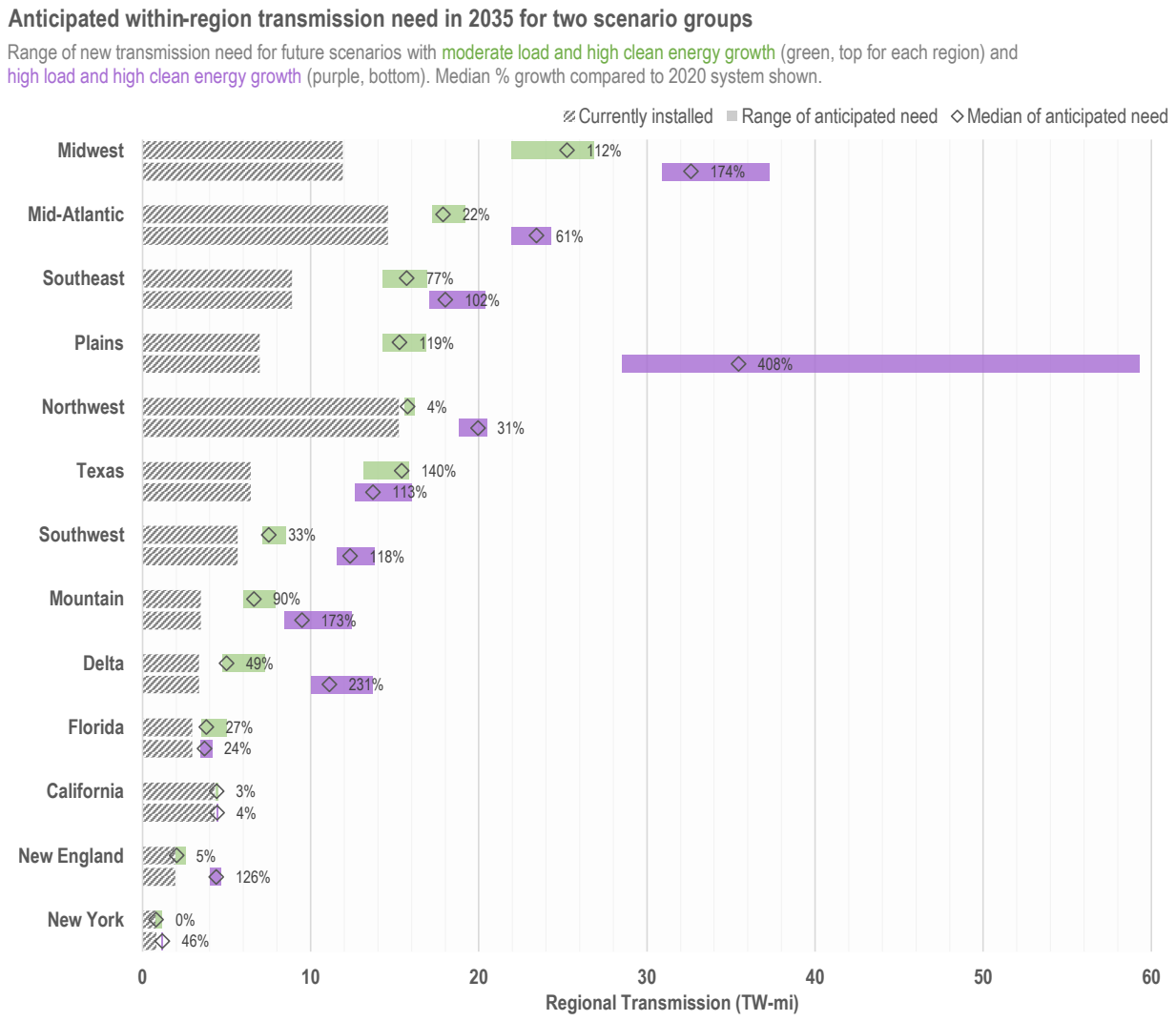
***Figure ES-4. Anticipated future regional transmission and interregional transfer capacity need in 2035 for the contiguous United States across three scenario groups.***

The capacity expansion modeling results can be further analyzed to describe specific within-region and interregional transmission needs, as shown in Figure ES-5 and Figure ES-6. The largest relative growth of regional transmission deployment (*see* Figure ES-5) compared with the 2020 system will be needed in the Texas (140% median increase), Plains (119%), Midwest (112%), Mountain (90%), and Southeast (77%) regions by 2035 to meet moderate load and high clean energy growth future scenarios. These 2035 deployment needs increase even more under high load growth scenarios (*see* Figure ES-5, purple scenario group) for nearly all regions, but especially for the Plains (408% median increase), Delta (231%), Midwest (174%), and Mountain (173%) regions.

Large relative growth in interregional transfer capacity (*see* Figure ES-6) compared with the 2020 system will be needed between the Delta and Plains (414% median increase), New England and New York (255%), Midwest and Plains (175%), and between the Mid-Atlantic and Midwest (156%) regions by 2035 to meet moderate load and high clean energy growth future scenarios. Large interregional transfer capacity need is also found between the three

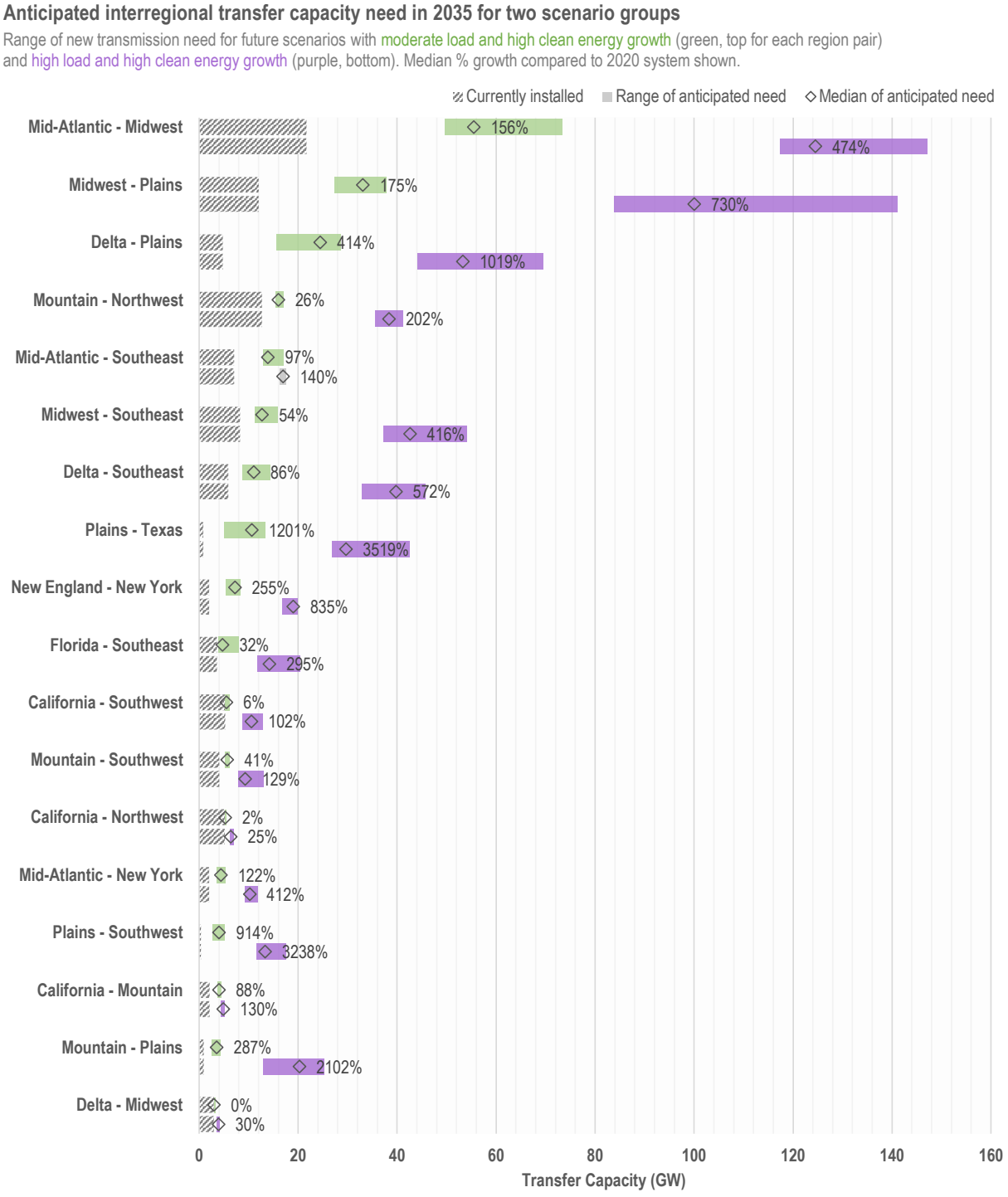
interconnections to help provide electricity given the evolution of supply and demand nationwide and to maintain reliability given an increase in extreme events that stress the grid.

Like the within-region transmission deployment need, high load scenarios further increase the interregional transfer capacity need for all regional pairs. These changes in interregional transfer capacity need are significant, with anticipated 2035 need ranging from 25% (median California – Northwest transfer) to 3519% (median Plains – Texas transfer) relative growth from the 2020 system (*see* Figure ES-6). Again, cross-interconnection transfers show the largest relative growth in anticipated need. Scenarios which include high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios.




*Note: Median and interquartile range of within-region transmission results given two different sets of scenarios for six different recent capacity expansion models. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a).*

***Figure ES-5. Anticipated future within-region transmission need in 2035 for the Moderate/High and High/High scenario groups.***

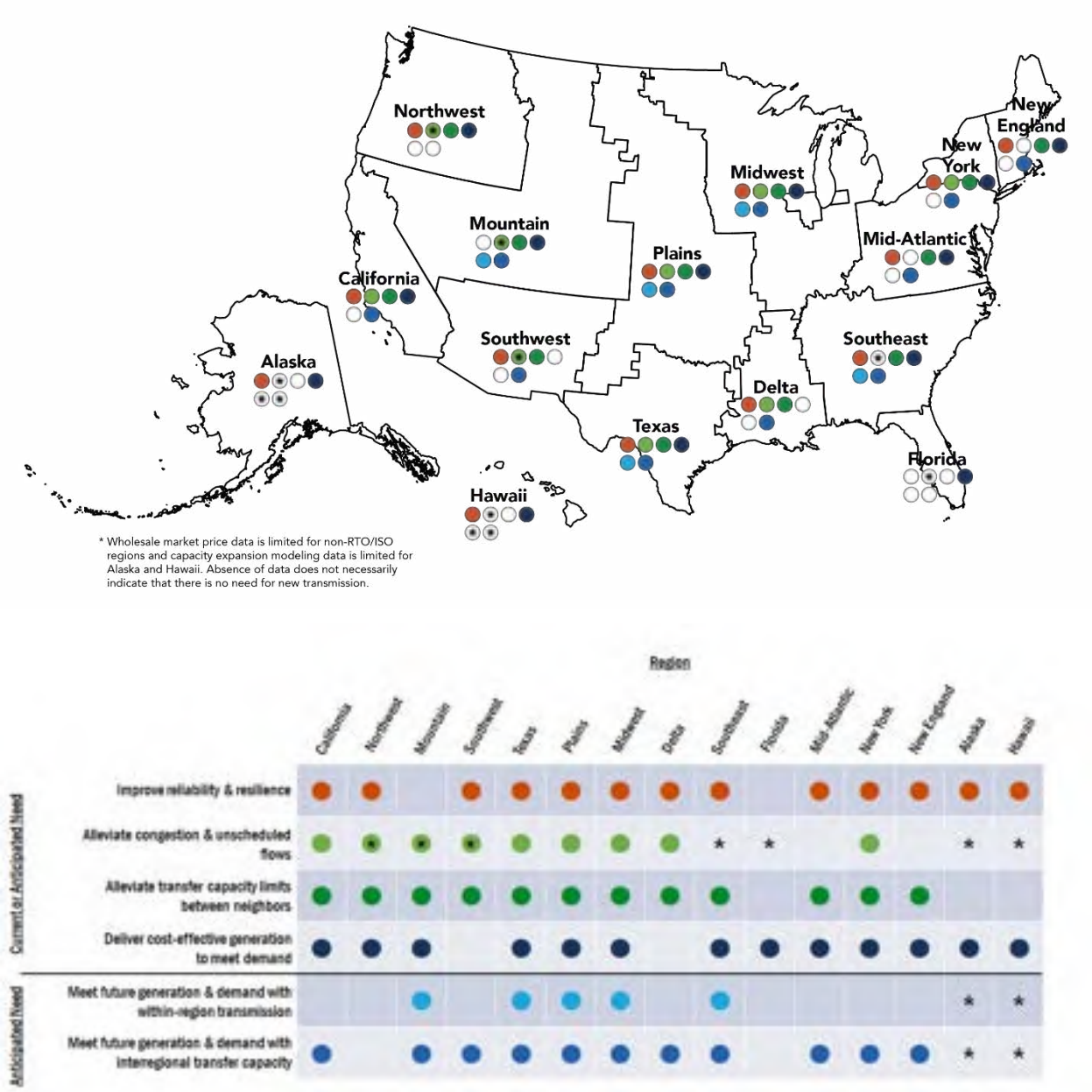



*Note: Median and interquartile range of interregional transfer results given two different sets of scenarios for six different recent capacity expansion models. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a).*

***Figure ES-6. Anticipated future interregional transfer capacity need in 2035 for the Moderate/High and High/High scenario groups.***

**Summary of Current and Anticipated Transmission Needs by Geographic Region**

Figure ES-7 summarizes findings of current and anticipated transmission needs by geographic region as determined by the data and studies referenced in the Section IV discussion of historical market conditions, Section V literature review, and Section VI national capacity expansion modeling results analysis. The different color circles located on the map of Figure ES-7 (top) correspond to the transmission needs listed in the dashboard (bottom).




*Source: See Supplemental Material for supporting references and methodology.*

***Figure ES-7. Summary of current and future transmission needs identified in Needs Study by geographic region.***

# Acronyms and Abbreviations

| | |
|---|---|
| AEA | Alaska Energy Authority |
| ATC | available transfer capability |
| BA | balancing authority |
| CAISO | California ISO |
| DER | distributed energy resource |
| DLR | dynamic line rating |
| DOE | U.S. Department of Energy |
| ERCOT | Electric Reliability Council of Texas |
| EIA | Energy Information Administration |
| EROS | Earth Resources Observation and Science |
| FERC | Federal Energy Regulatory Commission |
| FPA | Federal Power Act |
| GMO | Geospatial Management Office |
| HVDC | high-voltage direct current |
| IESO | Independent Electricity System Operator of Ontario |
| IIJA | Infrastructure Investment and Jobs Act |
| IQR | interquartile range |
| IRA | Inflation Reduction Act |
| ISO | independent system operator |
| ISO-NE | ISO New England |
| JTIQ | Joint Transmission Interconnection Queue |
| KIUC | Kaua'i Island Utility Cooperative |
| LRTP | Long-Term Regional Transmission Plan |
| MISO | Midcontinent Independent System Operator |
| NEPA | National Environmental Protection Agency |
| NERC | North American Electric Reliability Corporation |
| NIETC | National Interest Electric Transmission Corridors |
| NRCS | Natural Resources Conservation Service |
| NREL | National Renewable Energy Laboratory |
| NYISO | New York Independent System Operator |

| | |
|---|---|
| PFC | power flow controllers |
| R&D | research and development |
| RAPID | Regulatory and Permitting Information Desktop |
| RTO | regional transmission organization |
| SEEM | Southeastern Energy Exchange Market |
| SEMA | Southeastern Massachusetts |
| SPP | Southwest Power Pool |
| TLR | transmission loading relief |
| TVA | Tennessee Valley Authority |
| VER | variable energy resources |
| WECC | Western Electricity Coordinating Council |
| WEIM | Western Energy Imbalance Market |
| WEIS | Western Energy Imbalance Service |
| WIUFMP | Western Interconnection Unscheduled Flow Mitigation Plan |

# NATIONAL TRANSMISSION NEEDS STUDY

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# I. Introduction

A robust transmission system is critical to the Nation's economic, energy, and national security, and the U.S. Department of Energy (the Department or DOE) is using a variety of tools to address challenges to expanding and upgrading the nation's transmission infrastructure to meet current and future needs.[3] As one part of that effort, DOE undertakes this Needs Study to identify high-priority national electric transmission needs—specifically, to identify geographic areas where the bulk power grid would benefit from new, uprated, or upgraded transmission facilities.

This Needs Study will inform DOE as it coordinates the use of its authorities that relate to electric transmission.[4] For example, the results of this needs assessment can inform DOE's work implementing various provisions of the Infrastructure Investment and Jobs Act[5] (IIJA) and the Inflation Reduction Act relating to transmission expansion, grid resilience, and grid technology. This Needs Study will also support the implementation of existing Department programs, including the Department's numerous funding programs, technical assistance and broader transmission planning activities, and the potential designation of National Interest Electric Transmission Corridors (NIETC, pronounced \NIT-see\). DOE expects that this Needs Study will also help inform existing industry-led transmission planning processes, including the regional transmission planning processes conducted in accordance with Federal Energy Regulatory Commission (FERC) regulations and policies.

One of the underlying authorities for this Needs Study is Section 216 of the Federal Power Act (FPA), which as amended directs DOE and FERC to take specific actions aimed at accelerating electric transmission development. Section 216(a)(1) of the FPA directs the Department to conduct assessments of national electric transmission capacity constraints and congestion not less frequently than once every 3 years.[6] Pursuant to Section 216(a)(1) and (3) of the FPA, DOE has initiated and will continue to consult with affected states, Indian Tribes, and appropriate regional entities. Section 216(a)(2) of the FPA directs DOE to issue a report based on the study conducted under Section 216(a)(1) or other information related to electric transmission capacity constraints and congestion, which may designate one or more NIETCs.

This Needs Study does not designate NIETCs. In accordance with Section 216(a)(2), DOE may issue a report that designates a NIETC in a geographic area that is experiencing or is expected to experience electric energy transmission capacity constraints or congestion that adversely affects consumers. Such a report would be based on the information included, and the findings made, in this Needs Study and other information relating to electric energy transmission

[3] U.S. Department of Energy, Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, 87 Fed. Reg. 2769 (Jan. 19, 2022), https://www.govinfo.gov/content/pkg/FR-2022-01-19/pdf/2022-00883.pdf.

[4] As noted in the Notice of Intent for the Building a Better Grid Initiative, DOE intends to launch a coordinated transmission deployment program to implement both IIJA and previously enacted authorities through studies and funding. The notice provided further background on the Department's tools and authorities to accelerate transmission deployment. See 87 Fed. Reg. at 2770–73.

[5] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).

[6] See 16 U.S.C. 824p.

capacity constraints or congestion. Prior to issuing its report designating a NIETC, DOE would consider alternatives and recommendations from interested parties (including an opportunity for comment from affected states and Indian Tribes). Section 216(a)(4) lists other factors that the Department may consider in determining whether to designate a NIETC, including the energy independence and energy security of the United States and reduction in the cost of electric energy for consumers.[7] On May 15, 2023, the Department published a Notice of Intent and Request for Information (RFI) in which it explained its intent to evaluate the designation of NIETCs on a route-specific basis and requested public comment on this proposal.[8] After evaluating comments to this RFI and giving the matter due consideration, DOE expects to issue guidance on the process it will use to designate NIETCs.

Although this Needs Study builds on findings from previous congestion studies (DOE 2020a), its scope has expanded because amendments to FPA Section 216 enacted in the IIJA require examination of both current and expected transmission capacity constraints and congestion. Consequently, this Needs Study includes an analysis of historical and anticipated electric transmission needs, defined as the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists would benefit from an upgraded, uprated, or new transmission facility—including alternative transmission solutions—to improve the reliability and resilience of the power system; alleviate transmission congestion and unscheduled flows; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to meet demand; and/or meet projected future generation, electricity demand, or reliability requirements.

This report is being disseminated by the Department of Energy. As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Public Law 106-554) and information quality guidelines issued by the Department of Energy.

## I.a. How to Use This Needs Study

The findings of this Needs Study are intended to inform regional and interregional planning, as well as help guide the Department in the execution of its transmission-related authorities. The Department understands the factors that drive industry transmission planning today and the entities and institutions that perform such planning.[9] This Needs Study is not meant to displace these planning processes or the reliability standards they address. Rather, the Department believes it will be an important addition to overall industry and government planning efforts to reduce transmission congestion and capacity constraints that adversely affect consumers.

[7] See note 16, infra, and accompanying text for further discussion of FPA Section 216(a)(4).
[8] U.S. Department of Energy, Notice of Intent and Request for Information: Designation of National Interest Electric Transmission Corridors (May 15, 2023), 88 Fed. Reg. 30956.
[9] Transmission planning is predominantly conducted today by local utilities, who plan for transmission needs on their respective transmission systems, and regional planning authorities formed under FERC Order 1000, which plan for regional needs and identify regional transmission projects that are more efficient or cost-effective solutions. *See* Order No. 1000, 136 FERC ¶ 61,051.

This Needs Study assesses the multiple drivers of current and anticipated transmission system needs within and across geographic regions, and it underscores the national commonalities of transmission need as the power sector continues to evolve. The findings of this Needs Study also highlight the potential for additional or upgraded transmission infrastructure to address multiple power sector needs and to generate a wide range of cross-cutting value. The Department expects that transmission planning entities will find it useful to consider these findings to explore a wider set of transmission infrastructure benefits in their respective planning processes and consider evaluating the benefits of potential future transmission facilities together as part of proposed project portfolios rather than evaluating benefits on an incremental project-by-project basis. As demonstrated by findings and resources in this Needs Study, holistic, multivalue transmission expansion planning can allow for transmission solutions to meet multiple planning objectives and can lead to a more efficiently planned, cost-effective bulk power system.[10]

This Needs Study also provides an assessment of anticipated transmission needs and value under various future transmission system considerations, including forecasted increases in variable energy generation, extreme weather events, and load growth, among others. For example, findings highlight the complexities of planning for future energy systems with increased variable and distributed energy resources (DERs) that are due to policy and consumer demand drivers and the value of transmission in accommodating such a future resource mix. Similarly, recent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures. The Department notes transmission planning entities may use these Needs Study findings as an informative basis to conduct more granular, scenario-based transmission studies with longer planning horizons to inform more comprehensive planning assessments.[11] Transmission planning efforts may also consider the findings of this Needs Study to reevaluate the historic weather data used in system planning and ensure it includes the type and frequency of extreme events likely to occur more regularly in the future. Further, transmission planning entities can consider if internal plans for transmission development will meet the anticipated transmission and interregional transfer capacity needs identified by national capacity expansion models aggregated in this Needs Study. If future transmission plans do not match general trends in published findings of transmission need and the results of multi-scenario capacity expansion models, planning scenarios can be modified to better capture future power sector projections.

In addition to assessments of transmission need and benefits, this Needs Study recognizes and considers additional factors not traditionally captured by more narrowly focused transmission planning processes, including flexibility and optionality considerations. As a result, the

[10] *See also* DOE discussion of incorporating a wider set of transmission benefits and evaluation of portfolios in transmission planning efforts in comments filed in response to FERC's Advance Notice of Proposed Rulemaking in Docket No. RM21-17-000, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=D8C2B9C9-DA24-CE62-9C9F-835CB6700000.

[11] *See id.* for additional DOE discussion of long-range, scenario-based transmission planning benefits.

Department notes transmission planning entities may wish to consider alternative transmission solutions as part of existing planning processes.[12] For example, alternative transmission solutions, such as grid-enhancing technologies, have been deployed on the existing grid to enhance asset utilization, mitigate curtailments of generation resources, and better manage congestion patterns. Leveraging emerging technologies to increase operators' visibility of power system flows and status of critical components can serve to improve grid security while maintaining reliability and making capacity available to alleviate constraints at lower cost.

Transmission planning entities may also find this Needs Study helpful in guiding coordinated transmission planning and development efforts across systems and regions. These Needs Study findings identify the challenges and value of planning interregional transmission, as well as the geographic regions most in need of increased interregional transmission capacity. These findings can serve as a foundation for transmission planners to harmonize transmission planning processes with neighboring planning authorities and increase coordination and collaboration to develop joint transmission studies and interregional solutions.

States would also benefit from incorporating the findings contained in this Needs Study into their own regulatory and planning processes given their key role in guiding transmission planning efforts through resource procurement targets or through state-led solicitations for transmission infrastructure, as well as their ability to influence regional planning authority transmission planning decision-making through participation in stakeholder processes. Further, states and local governments would also benefit from incorporating the findings contained in this Needs Study in their respective transmission siting and approval processes. As demonstrated by this Needs Study, transmission needs and potential solutions are often regional and interregional in nature and therefore do not begin or end at state boundaries, making collaboration among states critical. States can consider the regional transmission needs discussed in this study and coordinate with neighboring states to identify, plan, approve, and advocate for transmission solutions that both advance state-level policy goals and broader electricity consumer needs. Similarly, states may collaborate among themselves and with regional planning authorities and federal agencies to facilitate cost-effective interregional transmission.[13]

## I.b. Study Organization

This study is organized as follows:

Section II provides the legislative language under which DOE has performed this study.

Section III introduces the role of transmission in the power system, benefits provided by transmission, and challenges to transmission expansion. The section includes an overview of the physical factors and grid-reliability considerations that lead to constraints within the transmission system and clarifies the relationship between transmission constraints and

[12] *See id.* for additional DOE discussion of additional factors, including technology trends, which transmission planners may consider incorporating into transmission planning efforts.
[13] *See id.* for additional DOE discussion of the importance of accommodating a diversity of jurisdictional interests, including those at the state level, in transmission planning efforts.

congestion. It then reviews regional variations in the approaches used to manage congestion and resolve capacity constraints.

Section IV discusses trends in transmission investments and what they indicate about transmission infrastructure needs. The section reviews several metrics assessing historical transmission investment, including load-weighted capital investment in new transmission and circuit-miles of transmission. It then examines historical market price differentials and wholesale market prices within and across regions to understand trends in congestion and quantify the value of interregional transmission. Finally, the section presents data from generation interconnection queues to further demonstrate the need for new transmission infrastructure.

Section V synthesizes DOE's key findings from a literature review of the historical and anticipated drivers, benefits, and challenges of expanding U.S. transmission infrastructure. The reports and literature reviewed by DOE are from a wide variety of sources and a cross section of the electricity sector. Common topics across reviewed reports include reliability and resilience, regional congestion, generation and load concerns, alternative transmission solutions, and siting and land use considerations.

Section VI outlines anticipated future transmission needs from the results of available national capacity expansion models encompassing multiple scenarios of potential future demand and clean energy growth. The section details electricity demand and generation assumptions across scenarios and the resulting need for regional deployment of transmission and interregional transfer capacity expansion under a wide variety of potential futures.

Section VII reviews the Department's process in preparing this study. The section describes the Department's consultation with states, Indian Tribes, and regional entities on a consultation draft of the study, as required by FPA Section 216. It further describes the process by which the Department solicited public feedback, including a list of entities who submitted comments during the public comment period.

Appendix A provides fact sheets for the nation as a whole as well as individual regions. These fact sheets are intended to summarize high-level Needs Study findings for wide audiences.

Appendix B provides a synthesis of the comments received on the draft Needs Study during the public comment period and the Department's response to those comments. All comments received during the public comment period can be found on the Department's website, as described in Section VII.

Supplemental Material, which contains supporting information about regional and interregional congestion and further detail on the capacity expansion modeling studies used to discuss anticipated transmission need, can be found online to accompany this Needs Study.[14]

[14] Supplemental Material and more information related to this Needs Study can be found at https://www.energy.gov/gdo/national-transmission-needs-study.

# II. Legislative Language

Congress has granted the Secretary of Energy (Secretary) various authorities to examine and implement programs supporting electric grid reliability and resilience. The IIJA directs the Secretary to establish several programs for grid infrastructure resilience and reliability, including, but not limited to, in the following provisions: Section 40101 (Preventing Outages and Enhancing Resilience of the Electric Grid); Section 40103(b) (Program Upgrading Our Electric Grid and Ensuring Reliability and Resiliency); Section 40106 (Transmission Facilitation Program); and Section 40107 (Deployment of Technologies to Enhance Grid Flexibility). The Inflation Reduction Act also includes relevant authorities, including Section 50151 (Transmission Facility Financing); Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines); and Section 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis).

Further, Section 40105 of the IIJA amends Section 216 of the FPA. This Needs Study implements Section 216(a)(1) of the FPA, as amended, which directs the Secretary to "conduct a study of electric transmission capacity constraints and congestion" at least once every three years.[15] As the purpose and underlying authority of this Needs Study is broad, the scope of this study is not constrained solely to the analytical direction set forth in Section 216(a)(1) of the FPA. The Needs Study can also assist the Secretary in evaluating the criteria necessary for designation of a National Interest Electric Transmission Corridor (NIETC), as provided by Section 216(a).[16] Section 216(a)(2) of the FPA directs DOE to issue a report, which may designate a NIETC(s) based on the information provided in the Needs Study or other information relating to electric transmission capacity constraints and congestion. In addition to the authorities provided in the IIJA, DOE maintains existing authorities to perform grid-related research and development (R&D) programs, including under the Energy Policy Act of 2005, Section 925 (Electric Transmission and Distribution Programs) and Section 936 (R&D into Integrating Renewable

[15] 16 U.S.C. 824p(a)(1).

[16] Section 216(a)(2) gives the Secretary authority to designate a NIETC in any geographic area that: "(i) is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers; or (ii) is expected to experience such energy transmission capacity constraints or congestion." 16 U.S.C. 824p(a)(2). In determining whether to designate a NIETC, the Secretary may consider whether:
"(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
(B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted;
(C) the energy independence or energy security of the United States would be served by the designation;
(D) the designation would be in the interest of national energy policy;
(E) the designation would enhance national defense and homeland security;
(F) the designation would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid;
(G) the designation—(i) maximizes existing rights-of-way; and (ii) avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites; and
(H) the designation would result in a reduction in the cost to purchase electric energy for consumers."
16 U.S.C. 824p(a)(4).

Energy onto the Electric Grid); Energy Independence and Security Act of 2005, Title XIII (Smart Grid Programs); and Energy Act of 2020, Sections 8001–8004 (Grid Modernization R&D Programs). DOE exercises other financing authorities that support grid infrastructure development, such as those implemented through the Loan Programs Office[17] and Transmission Infrastructure Program.[18]

Lastly, to ensure the federal government, states, and the public have access to and can obtain reliable energy information, Congress granted the Secretary broad authorities to collect and study information as the Secretary determines necessary to help formulate energy policy.[19] This broad grant of authority is in addition to, and not in limitation of, any other authority of the Secretary.

[17] For example, under the Title 17 Innovative Energy Loan Guarantee Program and the Tribal Energy Loan Guarantee Program, the Department is authorized to provide loan guarantees to projects that will expand and improve the transmission grid.

[18] The Transmission Infrastructure Program implements Section 402 of the America Recovery and Reinvestment Act of 2009, which amended Section 301 of the Hoover Power Plant Act of 1984. The Transmission Infrastructure Program is a federal infrastructure development assistance and financing program that manages the Western Area Power Administration's statutory $3.25 billion borrowing authority to provide debt financing and development assistance for qualifying transmission projects with at least one terminus in its 15-state service territory and that also facilitate delivery of renewable energy. *See* https://www.wapa.gov/transmission/TIP/Pages/AboutTIP.aspx.

[19] *See, e.g.,* 15 U.S.C. 772(a) and 796; 42 U.S.C. 7135(b).

# III. Transmission Concepts

This section introduces key transmission concepts. First, it describes the role of transmission in the operation of the bulk power system and provides a brief overview of the benefits of transmission to consumers and the challenges to transmission expansion. Second, it discusses the physical factors and grid-reliability considerations that create constraints within the transmission system, which in turn can cause congestion during system operations. Finally, the section reviews regional variations in the approaches historically used to manage congestion in the Eastern and Western U.S. Interconnection transmission systems. The congestion management practices include:

- Centralized unit commitment and economic dispatch procedures used in areas operated by regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTO/ISO);
- Transmission services requests based on posted available transfer capability (ATC) information used in non-RTO/ISO areas;
- Transmission loading relief (TLR) used in real-time operation in both RTO/ISO and non-RTO/ISO areas; and
- The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) used in the non-RTO/ISO areas in the Western Interconnection.

Unlike prior studies, this Needs Study does not review historic ATC and TLR data in identifying persistent congestion, except where ATC or TLR analysis was provided in the industry reports reviewed for this study. Instead, the Department uses a market price differential metric developed by FERC (2017) to identify persistent congestion.[20] ATC and TLR procedures are discussed in this section along with other congestion management schemes to provide a comprehensive view of the congestion management methods used in the U.S. power sector.

The WIUFMP was used for the first time in this Needs Study to identify congested areas in the Western Interconnection. Accepted by FERC in March 2016, the Plan monitors real-time flows on selected transmission paths where congestion is significant and could affect grid reliability, and it uses control devices and curtailment to manage congestion and unscheduled flows on the grid.

## III.a. Role of Transmission in the Power Sector

The Nation's transmission system facilitates the transfer of electricity from power supply sources, such as generating stations, to load centers where the power will be used. Transmission networks are designed to transport energy over long distances with minimal power losses, which is achieved by boosting voltages at specific points along the electricity supply chain. In the United States, transmission lines are typically rated between 69 kilovolts

[20] Starting with ABB Velocity Suite data through 2014, FERC staff found 1,986 generator or load points in FERC-jurisdictional RTOs/ISOs where relatively high or low real-time locational marginal prices occurred persistently. FERC (2016) provides a discussion of congestion metrics based on transmission loading relief and on wholesale electricity price differentials.

(kV) and 765 kV, although exceptions can occur depending on the function of the line.[21] Lines rated 230 kV and above are generally used to deliver power across long distances, such as between states or regions. The bulk power system refers to all facilities and control systems necessary for operating an interconnected electric energy transmission network or any portion thereof (NERC 2023).

Transmission can refer to any facility that helps in the delivery of power from where it is generated to where it is used. Transmission lines are currently the primary means to connect remote generation sources to the locations of electricity demand. The underlying transmission network facilitates the delivery of large amounts of power from utility-scale power generation installations to consumers. Both traditional transmission wires and alternative transmission solutions can be employed to improve the efficiency of the grid, improve power quality, or enable power delivery at lower costs.

Transmission infrastructure is required to connect generation resources to the larger system so that energy can be delivered to load. As more generation is developed and load continues to increase, the transmission grid will reach its limit in many places. The capacity of the grid must be expanded through the addition of new infrastructure—such as transmission lines, substations, and transformers—or through rebuilds using components that provide higher ratings.

Transmission infrastructure improvements provide several benefits to consumers. Transmission improves grid reliability, resource adequacy, and resilience of the power system. Transmission also helps reduce congestion and losses, which can lead to economic benefits in the form of reduced electricity prices and reduced system costs. Relatedly, diversity in load, generation, and weather patterns within and between regions helps support resource adequacy and reliability; this diversity can typically be improved with increased transmission infrastructure, so long as regional planners consider and address the risks of interdependency between regions. New transmission advances clean energy goals by enabling greater access to the best available and lowest cost clean energy resources, which can be in remote areas far from load and the existing transmission system. Many new energy resources that would help reduce power prices and meet reliability and clean energy goals are currently within backlogged interconnection queues and a more efficient transmission study process can help hasten connection of those resources to the grid. In areas with high generation resource penetration, transmission buildout can reduce resource generation curtailment and improve the output of renewable resources. A more robust transmission system—along with associated upgrades to the distribution system—supports the electrification of end-use devices that currently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved air quality and avoided adverse health effects. Lastly, investing in new lines results in increased employment, tax revenues, and resilience, as well as other economic development benefits. These benefits are gained directly via new and upgraded transmission infrastructure and with upgrades to distribution and generation associated with a more robust transmission network.

[21] The North American Electric Reliability Corporation (NERC) considers transmission lines to be facilities that carry electric energy at relatively high voltages varying from 69 kV to 765 kV (NERC 2022b).

Expanding transmission capacity, however, can be challenging. Navigating complex state processes and meeting federal and local requirements in efforts to permit and site new lines can be difficult and can result in long development periods. The problems are compounded for regional projects that cross multiple states and jurisdictions. Deciding who pays the cost of transmission capacity expansion is another challenge, one that can delay or even derail a project. Further, quantifying the benefits of transmission is not straightforward. For cases in which project approval or allocation of project costs depends on the benefits, disputes about the size of benefits or the beneficiaries can be a significant hurdle. Transmission projects also frequently face public opposition or "not-in-my-backyard" concerns for various reasons. These challenges can lead to increased costs, schedule delays, or even project cancellations.

# III.b. Transmission Needs

This study evaluates national transmission needs. For the purposes of this document, a *transmission need* is considered to be the existence of present or expected electric transmission capacity constraints or congestion in a geographic area.

***Transmission congestion.*** *Transmission congestion*[22] refers to the economic impacts on the users of electricity that result from operation of the system within the physical limits on the amount of electricity flow the system is allowed to carry to ensure safe and reliable operation (otherwise known as a *transmission constraint*[23]). For example, power flow could be constrained by the maximum thermal limit of a transformer or power line conductor. As a result, power is rerouted through less optimal paths to deliver more expensive generation while curtailing delivery of less expensive generation to safely meet customer demand. This process occurs either manually through operator intervention or automatically via Security Constrained Economic Dispatch.

A constraint on the transmission system that may drive transmission congestion could refer to:

- An element of the transmission system—for example, an individual piece of equipment, such as a transformer, or a group of closely related pieces of equipment, such as the conductors that link one substation to another—that limits power flows to avoid an overload that could cause one or more elements to fail and thereby jeopardize reliability;
- An operational limit imposed on an element or group of elements to ensure that the system, as a whole, will continue to operate reliably following the failure of one or more elements; or
- A transfer limitation established to manage flows in accordance with coordination agreements.

[22] Energy Information Administration (EIA) defines *congestion* as "a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously." (EIA 2022b)

[23] NERC and EIA define a transmission constraint as "a limitation on one or more transmission elements that may be reached during normal or contingency operations." (NERC 2022b) (EIA 2022b)

***Transmission constraints***. *Transmission constraints* are the result of many factors, including load level, generation dispatch, and the possibility of equipment failure. Jointly, these conditions establish a specific level or limit—as defined above (in the second case)—to the permissible flow of electricity over the affected element(s) under specific operating conditions, to ensure safe and secure operations in compliance with reliability rules.[24] Transmission operating limits, which specify the maximum throughput allowable on affected transmission elements, are created to comply with these nationally established and enforced reliability rules.

The three main transmission operating limits are thermal, voltage, and stability limits:

- Thermal limits: Transmission equipment is designed to operate within limits that depend on the physical properties of the equipment. As electricity flows through a line, it heats the line. The thermal limit is based on the operating temperature of the conductor. Exceeding the limit can cause the line to overheat and sag excessively, posing safety problems if the line contacts vegetation or other items within or close to the right-of-way. Extreme overheating can lead to annealing, which will change the metallic properties of the line and compromise its integrity. The thermal limit ensures the line does not exceed its safe operating temperature.
- Voltage limits: To ensure reliability of the bulk power system, substation voltages must be close to their nominal voltages. Operating limits, which are set by equipment operators, specify the tolerances around the nominal levels. Voltages that are too high (overvoltages) or too low (undervoltages) can damage equipment and affect the ability to transfer power across the network. To avoid voltage violations, operators might place limits on the amount of power that can be transferred across some transmission facilities on the basis of system conditions.
- Stability limits: System stability refers to the ability of the power system to return to a stable operating point after a momentary disturbance, such as a fault, sudden change in load, or loss of a generator. To maintain system stability, planning standards specify acceptable frequency deviation tolerances during normal operations. In the United States, the bulk power system is operated at a nominal frequency level of 60 Hertz (Hz). Frequency deviations can occur when the operating frequency deviates outside the tolerance around 60 Hz (over or under frequency) or when voltage and current waveforms are not synchronized (phase deviations). Stability limits might be required to ensure that the power flow does not exceed levels that could pose a risk to system operations.

A fundamental responsibility of transmission system operators is to ensure reliable operation of the transmission system within these limits. This responsibility is executed by referring to transmission operating limits when approving or denying transmission service requests by parties seeking to use the transmission system. Operators practice congestion management to ensure both reliable operation and economic efficiencies.

[24] Reliability standards developed by NERC and approved by FERC specify how equipment or facility ratings are to be established to avoid exceeding thermal, voltage, and stability limits (NERC 2022b).

***Transmission capacity constraint.*** While *transmission congestion* (and the related but not identical *transmission constraint)* have industry standard definitions, *transmission capacity constraint* does not. We define it here to be a suboptimal limit of transfer of electric power on the grid, including those that reduce operational reliability of the power system; power transfer capability[25] or capacity[26] limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of cost-effective generation to be delivered to high-priced demand.

## III.c. Transmission Regions

Several different entities are responsible for regional transmission planning, transmission system operations, and reliability. The RTOs/ISOs operate and facilitate wholesale markets to connect generators and load serving entities across their respective transmission systems. Seven RTOs/ISOs in the United States and two RTOs/ISOs in Canada operate on the North American power grid. Figure III-1 shows the illustrative boundaries of each organization.

*Source: ISO/RTO Council, at https://isorto.org/.*

***Figure III-1. Regional transmission organization/independent system operator footprints.***

[25] Transfer capability is defined in NERC (2022b) as "The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions."

[26] Transfer capacity does not have an industry standard definition but commonly refers to the ability of a transmission line to transfer power without causing facility overloads under contingency and is calculated considering the electrical and physical parameters of the line given the normal ambient conditions in its location.

Regional transmission planning occurs within the FERC Order 1000 Transmission Planning Regions (Order 1000 regions) and the Electric Reliability Council of Texas (collectively, transmission planning entities). The seven U.S. RTOs/ISOs serve as Order 1000 regions in their territories. The Order 1000 regions for 2021 are shown in Figure III-2.

*Source: Federal Energy Regulatory Commission at [https://www.ferc.gov/media/regions-map-printable-version-order-no-1000](https://www.ferc.gov/media/regions-map-printable-version-order-no-1000).*

***Figure III-2. Federal Energy Regulatory Commission Order 1000 regions.***

Six regional reliability entities oversee the development and implementation of mandatory national and regional reliability standards within the North American bulk power system. Regional reliability entity boundaries are shown in Figure III-3 below. Similarly, the RTOs/ISOs often serve this reliability coordination function in conjunction with their associated Reliability Entity.

| | |
|---|---|
| MRO | Midwest Reliability Organization |
| NPCC | Northeast Power Coordinating Council |
| RF | ReliabilityFirst |
| SERC | SERC Reliability Corporation |
| Texas RE | Texas Reliability Entity |
| WECC | WECC |

*Source: North American Electric Reliability Corporation (NERC 2021).*

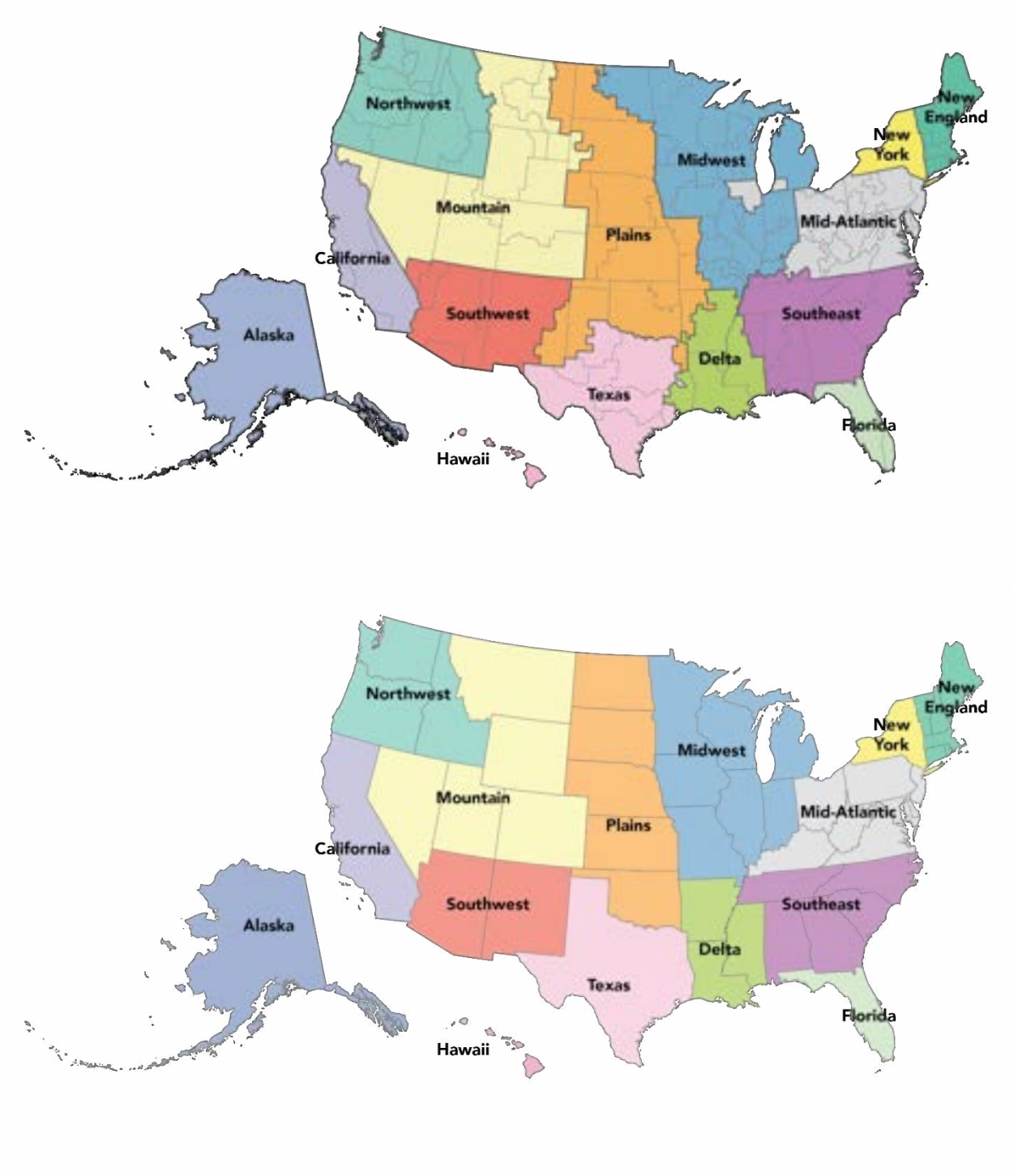
***Figure III-3. Regional reliability entities.***

This study organizes transmission need results by geographic region, to the extent possible. If data sources are specific to an RTO/ISO, Order 1000 region, or regional reliability entity, the appropriate power system entity name may also be used. For example, the wholesale market prices that underlie the analysis presented in Section IV.b. rely on historical prices from the RTOs/ISOs, so those names are used in that section. Otherwise, a geographic naming convention is adopted here. Figure III-4 shows the geographic regions used in this analysis, the boundaries of which were chosen to represent the unique boundaries of the power system entities. Table III-1 identifies the geographic region nomenclature used in this study and the principal power system entity associated with that geographic area for completeness.

***Table III-1. Region names used throughout this report. The dominant power system entities that serve transmission planning, transmission system operations, and reliability functions in each geographic region are also presented.***

| Geographic Region | RTO/ISO | Transmission Planning | Reliability Entity |
|---|---|---|---|
| California | California Independent System Operator | California Independent System Operator | Western Electricity Coordinating Council |
| Northwest | – | Northern Grid | Western Electricity Coordinating Council |
| Mountain | – | Northern Grid & WestConnect | Western Electricity Coordinating Council |
| Southwest | – | WestConnect | Western Electricity Coordinating Council |
| Texas | Electric Reliability Council of Texas | Electric Reliability Council of Texas | Texas Reliability Entity |
| Plains | Southwest Power Pool | Southwest Power Pool | Midwest Reliability Organization |
| Midwest | Midcontinent Independent System Operator | Midcontinent Independent System Operator | Midwest Reliability Organization |
| Delta | Midcontinent Independent System Operator | Midcontinent Independent System Operator | SERC Reliability Corporation |
| Southeast | – | Southeastern Regional Transmission Planning & South Carolina Regional Transmission Planning | SERC Reliability Corporation |
| Florida | – | Florida Reliability Coordinating Council | SERC Reliability Corporation |
| Mid-Atlantic | PJM | PJM | Reliability First |
| New York | New York Independent System Operator | New York Independent System Operator | Northeast Power Coordinating Council |
| New England | ISO New England | ISO New England | Northeast Power Coordinating Council |

*Source: Transmission planning entities from Federal Energy Regulatory Commission at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000 and Reliability Entity names from North American Electric Reliability Corporation (NERC 2021).*




*Source: National Renewable Energy Laboratory.*

*Note: Geographic boundaries that align with the Reliability Entity and the transmission planning entities (top) are used whenever possible. If underlying data were only available at the state-level, then geographic boundaries align with state boundaries (bottom). Alaska is not to scale.*

***Figure III-4. Geographic regions used to present study results in this analysis, where appropriate.***

# III.d. Regional Practices for Managing Congestion

FERC Order Nos. 888 and 889 promulgated rules for the use of the U.S. portions of the transmission systems in the Eastern and Western Interconnections. The orders sought to ensure nondiscriminatory access to the transmission system. RTOs/ISOs use market-based approaches for allocating ATC on the basis of users' expressed willingness to pay for transmission services. Non-RTO/ISO transmission system providers use administrative approaches to allocate transmission capacity, announcing the availability of transmission service and accepting requests for such service on a nondiscriminatory basis. Both RTO/ISO and non-RTO/ISO transmission providers also rely on specialized procedures for managing the operations of the transmission system in real time.

## RTO/ISO congestion management practices

RTOs/ISOs use centralized unit commitment and economic dispatch procedures driven by competitive offers from generators to sell electricity to purchasers. These procedures account for all transmission constraints to form a marginal price at each point within the transmission system, that is, the point at which wholesale electricity is either injected into the system by a seller or withdrawn by a purchaser. When no transmission or generation constraints are restricting economic dispatch and all desirable transactions are occurring, all the marginal prices at all points will be identical, apart from the effect of transmission losses. If a constraint is present, the marginal prices on the two sides of the constraint will differ. The difference in price is an economic measure of the congestion cost.

If transmission investment removes a transmission constraint to relieve congestion, the investment will reduce congestion costs. Reducing load or increasing generation on the load side of a constraint will have a similar effect in reducing congestion costs. The congestion costs avoided are a direct measure of the economic benefit from, or value of, this investment. In actual cases, these benefits, intrinsically, might or might not be sufficiently large and recurrent to warrant the investment. Reducing congestion costs is not the only economic benefit (or non-economic benefit) that might justify a transmission investment, as discussed later in this study.

## Non-RTO/ISO congestion management practices

Transmission system operators that are not part of an RTO/ISO publicly post the ATC on their systems long in advance of real-time operations. These operators then receive, review, and either accept or deny users' requests for transmission service on a firm or non-firm basis at established rates.

ATC directly reflects how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

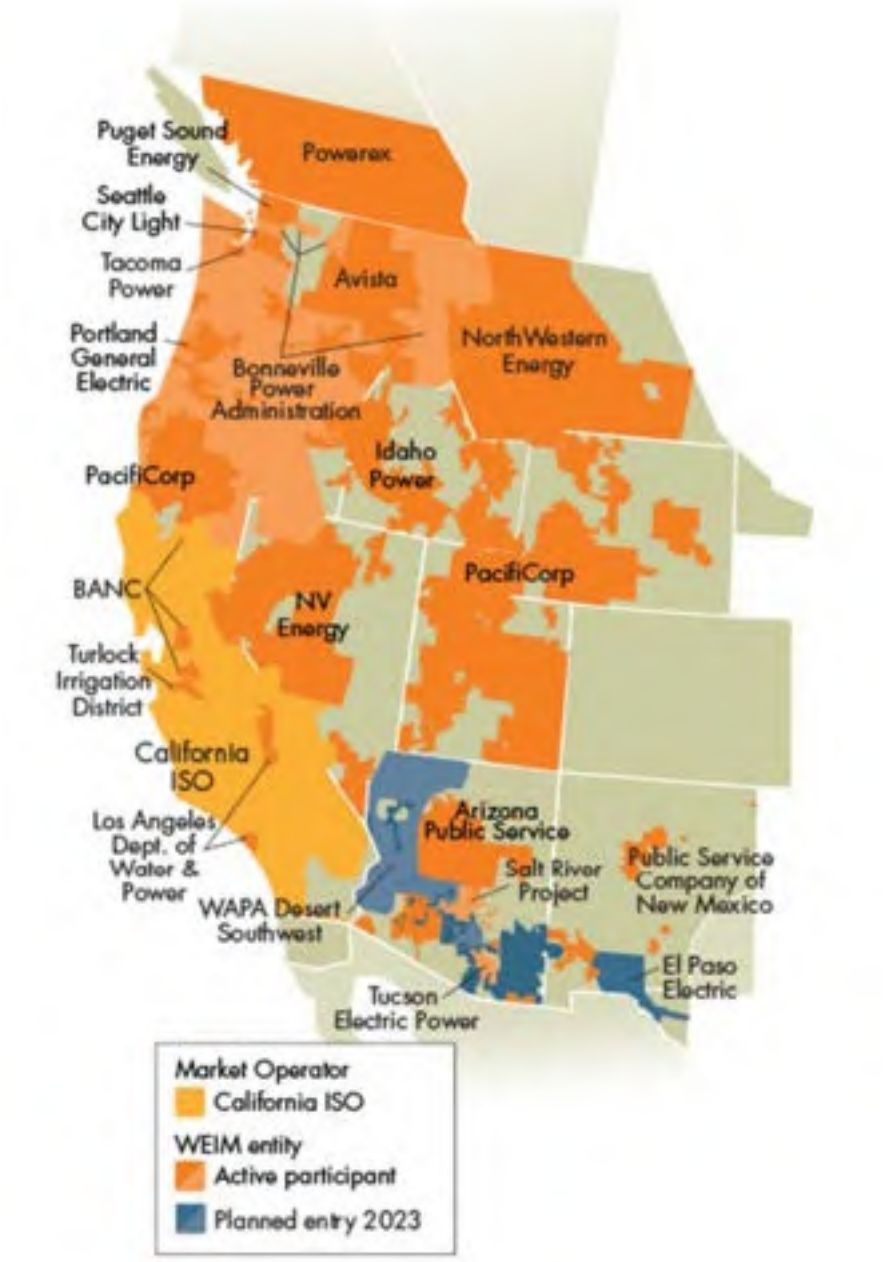
Denials of requests for transmission service provide a direct, but incomplete, measure of congestion. Denials are a direct measure because they reflect a desire to use the transmission system that was foregone because of one or more transmission constraints. But denials do not provide information on the economic significance of the congestion they represent and no

information on the value of transmission or other efforts to relieve the constraints that underlie this congestion. Information on denials of requests for transmission service is also an incomplete measure because it does not capture requests that were not made because of users' perceptions of the availability of services. That is, the availability of transmission services is routinely updated. Potential users seeking those services might forego requesting them at times of limited availability, in part because of experience of requests being denied under these conditions. An additional reason a desired service might not be requested is because the ATC had already been set to zero.

The RTO/ISO economic dispatch procedures that serve, in part, to manage congestion in real time are becoming available to the non-RTO/ISO regions through energy imbalance markets or services (Chen 2020). There are three active energy imbalance markets in the United States. In 2014, the California ISO (CAISO) launched the Western Energy Imbalance Market (WEIM), a real-time energy market that extended the market-based approach for congestion management in the real-time market beyond CAISO's footprint. By 2022, WEIM had expanded to include market participants in all states in the Western Interconnection except Colorado (*see* Figure III-5). Southwest Power Pool (SPP) began administering the Western Energy Imbalance Service Market for utilities in the Western Interconnection not currently part of an RTO/ISO in 2020 (SPP 2022). Utilities in the Southeast are in the process of developing the Southeastern Energy Exchange Market (SEEM) to trade energy in real time (SEEM 2022), an extension of the bilateral contracts currently used in that region. Despite these developments, however, information on the economic value of congestion outside RTOs/ISOs is minimal when compared with the market price differential data available from RTOs/ISOs and reviewed in this study.

## Specialized congestion management practices used in real-time operations

Transmission system operators of both types (i.e., RTO/ISO and non-RTO/ISO) also rely on specialized procedures for managing congestion during real-time operations. These procedures are necessary to ensure reliable operation of the power system when unforeseen events occur that alter the capabilities of the transmission system from those that were assumed when the requests for transmission service were made (e.g., unexpected outage of a transmission facility), or when conflicts arise among the services agreed upon by different transmission system operators.




*Source: California Independent System Operator Corporation at https://www.westerneim.com/Pages/About/default.aspx/. Licensed with permission from the CAISO. Any statements, conclusions, summaries, or other commentaries expressed herein do not reflect the opinions or endorsement of the CAISO.*

***Figure III-5. Western Energy Imbalance Market footprint.***

In the Eastern Interconnection, principally but not exclusively in the Southeastern regions served by non-RTOs/ISOs, transmission system operators use the TLR[27] administrative procedure to address congestion that arises in real time.[28] Five levels of TLR procedures can be invoked. TLR level 3 is the lowest level that involves curtailments of transmission service to ensure that constrained transmission facilities are not loaded beyond safe reliability operating limits. TLR level 5 is the most severe level; it involves reducing the levels of firm transmission service. Information on TLRs is posted publicly by North American Electric Reliability Corporation (NERC).[29]

TLRs of level 3 and above involve curtailments of, or reductions to, previously agreed-upon transmission services. TLRs are a direct measure of transmission congestion because the measurement represents transmission services that must be foregone because of a transmission constraint. They are not economic measures of congestion because, like denials of requested transmission service, they provide no information on the value of the transmission services that have been foregone. They also do not provide insight into expected future congestion.

## The Western Interconnection Unscheduled Flow Mitigation Plan

The WIUFMP was developed to manage congestion and loop flows in the Western Interconnection (PacifiCorp 2019).[30] Because of the topology of the transmission system in the West, transactions from the Northwest to California result in unscheduled energy (loop) flows into Wyoming, Colorado, New Mexico, and Arizona. Under the mitigation plan, stakeholders have identified Qualified Paths where congestion is significant enough to pose a reliability risk. To be included as a Qualified Path, a transmission path must have operated at or near its rated capacity for a minimum of 100 hours over the past 36 months, along with curtailments to manage the flow on the path. The path could also be susceptible to unscheduled flows. The WIUFMP manages congestion on the Qualified Paths using designated Qualified Controllable Devices and using curtailment when necessary. Qualified Controllable Devices are selected on the basis of their effectiveness in reducing unscheduled flows on the Qualified Paths.

[27] RTOs/ISOs in the Eastern Interconnection principally use price to manage congestion, and rarely invoke TLR, when compared with the non-RTO/ISO regions.
[28] In the Western Interconnection, the real-time administrative counterpart to the TLRs used in the Eastern Interconnection is called “unscheduled flow mitigation.” Unlike in the Eastern Interconnection, information on unscheduled flow mitigation in the Western Interconnection is not posted publicly.
[29] See https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.
[30] Revision 4 of the Western Interconnection Unscheduled Flow Mitigation Plan was filed with FERC by PacifiCorp on August 9, 2019, in Docket No. ER19-2566 (PacifiCorp 2019). The revised plan was accepted by FERC on October 9, 2019. The mitigation plan can be found online in FERC’s Docket eLibrary at https://elibrary.ferc.gov/. The mitigation plan is also hosted by SPP at https://www.spp.org/documents/62460/081919%20wiufmp%20tariff.pdf.

# IV. Current Transmission Need Assessment through Historical Data

Several indicators point to an immediate need for more transmission infrastructure. For example, wholesale market price differences across geographic locations directly assess the impact of congestion on the transmission system. Additional transmission could remove or reduce the variation in prices caused by congestion, allowing lower cost energy to reach high-demand areas. Examining price differences between RTOs/ISOs can also help identify the need for additional interregional transmission capacity to alleviate congestion and constraints negatively impacting consumers. Interregional transmission further supports the development of within-region transmission because load and generation patterns across multiple regional markets are less temporally correlated than within different subregions of a single market.

Furthermore, over the past several years, installation of new generators has been delayed because of longer wait times for interconnection agreements (Rand et al. 2022) and increased costs to connect to the electricity grid (Caspary et al. 2021). As described in the FERC Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (FERC 2022), these wait time and cost challenges are related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests that the "piecemeal" approach to transmission deployment that occurs with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process (FERC 2022).

This section explores recent trends in transmission investments and what they reveal about current transmission need. Section IV.a. reviews the past decade of transmission investments in each U.S. region guided by metrics as outlined in the *2017 Transmission Metrics Report* (FERC 2017). Section IV.b. considers transmission congestion that currently exists within each region by analyzing historical market price differentials across the contiguous United States. Section IV.b. further analyzes differences in simultaneous wholesale market prices between neighboring regions to quantify the congestion value of interregional transmission. Section IV.c. discusses qualified paths in the Western Interconnection. Section IV.d. presents nearly 20 years of historic data from the interconnection queues, demonstrating the amount of generation waiting to be connected to the grid.

## IV.a. Historical Transmission Investments

In 2016, FERC developed several metrics to assess historical transmission investment (FERC 2017). Two of these metrics show historical transmission investments—in terms of cost and circuit-miles—of projects installed annually in each region. To account for different sizes of the regions, both metrics are weighted by annual regional load.

Transmission investments are inherently "lumpy," or unevenly distributed. Many projects that have been in development for several years might all be energized in the same year, giving the

appearance of large investments during that single year without consideration of when projects first entered the development pipeline. To account for this lumpiness, temporal trends are presented using rolling averages, which differ from the metrics FERC has developed. FERC presented data from 2008 to 2015 in its metrics report (FERC 2017); we consider the decade of investments from 2011 to 2020.[31]

## Transmission investment decreased during the second half of the 2010s

Historic investments are measured both in terms of capital costs and circuit-miles of transmission based on the year the transmission project was put into service (i.e., *energized*). Figure IV-1 (top) shows the total annual capital costs of new and rebuilt transmission lines rated at least 100 kV in each region[32] between 2011 and 2020. To account for the inherent lumpiness of transmission investments, this is presented as the simple 3-year moving average of the annual sum of capital costs in each region. Capital costs for all interregional lines that terminate in different regions, or nations, are shown separately from those lines that begin and end in the same region. Figure IV-1 (bottom) shows the same information weighted by regional annual net load; that which is delivered by the transmission system and does not include behind-the-meter generation. The load-weighted costs for all regional and interregional projects are also shown ("Entire U.S.").

Figure IV-2 shows the total annual circuit-miles of the same transmission lines over the same time period as Figure IV-1. The decadal averages for all four metrics in each region are shown as horizontal lines in Figure IV-1 and IV-2, and listed in Table IV-1. It is important to note that the load-weighted capital costs shown in Figure IV-1 and Table IV-1 differ from the total transmission investments utilities in a given region may spend on an annual basis. The metrics presented here are focused on the capital costs of transmission lines that are energized in each year, which do not incorporate the ongoing development costs of those projects that will be energized in future years or the operation and maintenance costs of projects that are already in service.

Transmission investments steadily increased for the United States as a whole during the first half of the decade, followed by several years of decreased energization: an additional 560 circuit-miles were installed each year from 2011 to 2015 nationwide, but the rate of annual installs between 2016 and 2020 actually decreased to a negative 79 circuit-miles per year. The general year-over-year trends for project capital costs match those of circuit-mile investments in each region. Differences between the two metrics can be attributed to differences in

[31] Only a decade of regional transmission investments were analyzed, so any investments made prior to 2011 or after 2020 are not shown. Section VI of this report provides the total regional transmission capacity (terawatt-miles) in 2020 from (Denholm et al. 2022). The regions with the most transmission capacity in 2020 are the Northwest, Mid-Atlantic, Midwest, and Southeast, respectively. A comparison of cumulative regional transmission capacity can provide insights when combined with the annual investments presented in this section. For example, the high 2020 regional transmission capacity suggests that the Southeast—which installed few circuit-miles of transmission between 2011 and 2020—made large transmission investments prior to 2011.

[32] Hawaii is not shown in Figure IV-1 or IV-2 because no transmission projects were energized (MapSearch 2023).

transmission costs per mile across regions—driven by differences in terrain, population densities, etc.

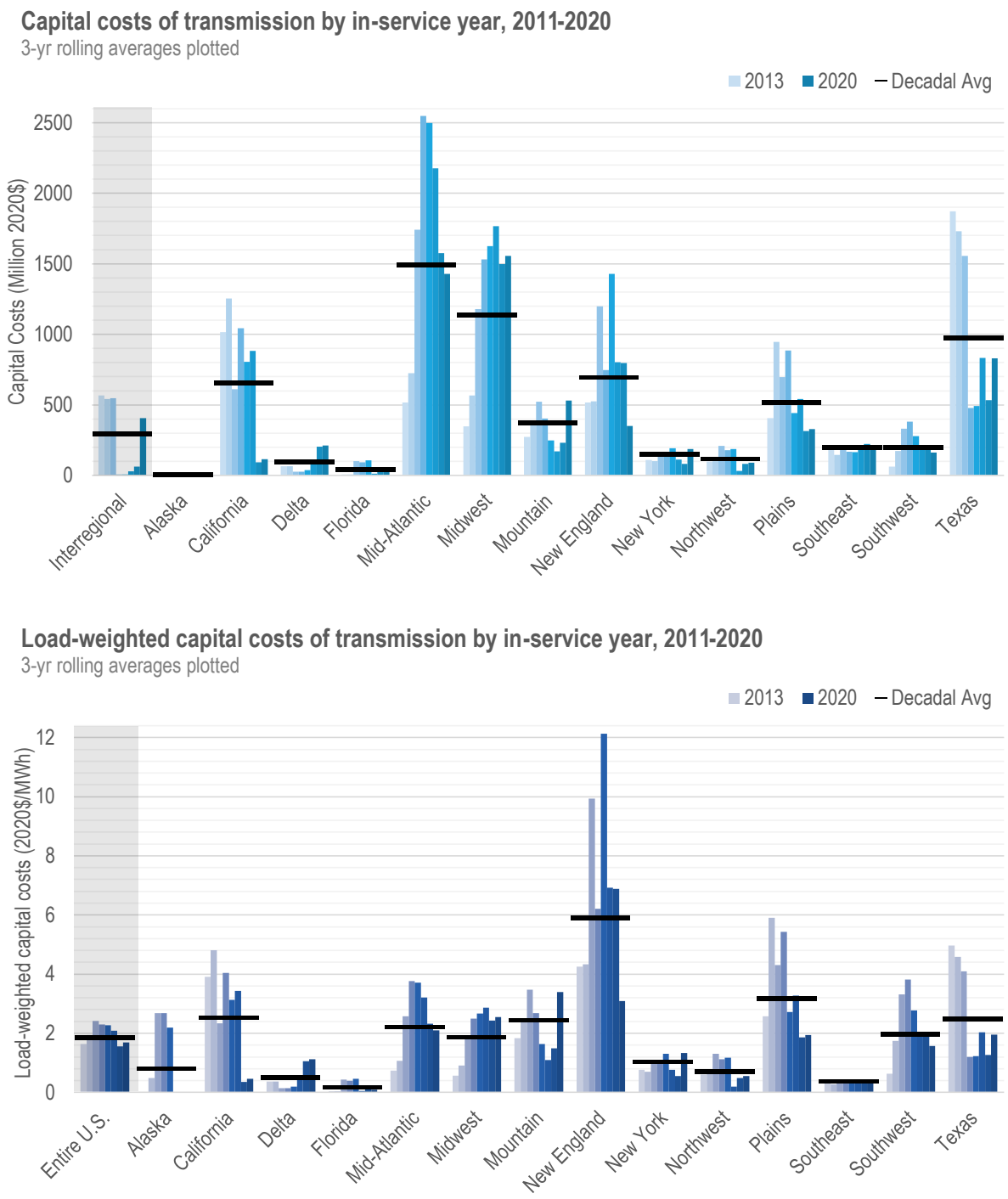
Investments in most regions—notably the Mid-Atlantic, Mountain, Plains, Southwest, and Texas—and interregional projects followed this overall national trend of increasing investments during the first half of the decade and decreasing investments during the second half. Some regions—notably California, Delta, and Midwest—steadily increased transmission capital cost investments through most of the decade. Texas built more circuit-miles than any other region in the first half of the decade. Alaska installed nearly 65 circuit-miles of transmission in 2014 and 2015, a relatively large investment compared with the annual load of the state. The Delta, Southeast, and Florida regions installed the fewest circuit-miles, relative to regional load, throughout the decade.

These investments resulted in a national total of 33,000 circuit-miles of either newly constructed or rebuilt transmission lines rated above 100 kV, which were energized between 2011 and 2020. Of these, 20,000 circuit-miles were higher capacity lines rated at least 345 kV (MAPSearch 2023).

***Table IV-1. Decadal average of annual sums of capital costs and circuit-miles—load weighted and not—for new and rebuilt transmission rated over 100 kV and energized between 2011 and 2020 across the entire U.S. and in each region individually.***

| Region | Capital Costs (Million 2020$) | Load-Weighted Capital Costs (2020$/MWh) | Circuit-Miles (ckt-mi) | Load-Weighted Circuit-Miles (ckt-mi/TWh) |
|---|---|---|---|---|
| Entire U.S. | 6,900 | 1.8 | 3,300 | 0.88 |
| Interregional | 290 | N/A | 72 | N/A |
| Alaska | 5.0 | 0.81 | 4.6 | 0.75 |
| California | 650 | 2.5 | 96 | 0.37 |
| Delta | 95 | 0.51 | 41 | 0.22 |
| Florida | 41 | 0.17 | 21 | 0.09 |
| Mid-Atlantic | 1,500 | 2.2 | 360 | 0.53 |
| Midwest | 1,100 | 1.9 | 670 | 1.1 |
| Mountain | 370 | 2.4 | 260 | 1.7 |
| New England | 690 | 5.9 | 150 | 1.3 |
| New York | 150 | 1.0 | 100 | 0.68 |
| Northwest | 110 | 0.70 | 70 | 0.43 |
| Plains | 520 | 3.2 | 410 | 2.5 |
| Southeast | 200 | 0.37 | 110 | 0.21 |
| Southwest | 200 | 2.0 | 140 | 1.4 |
| Texas | 970 | 2.5 | 800 | 2.1 |

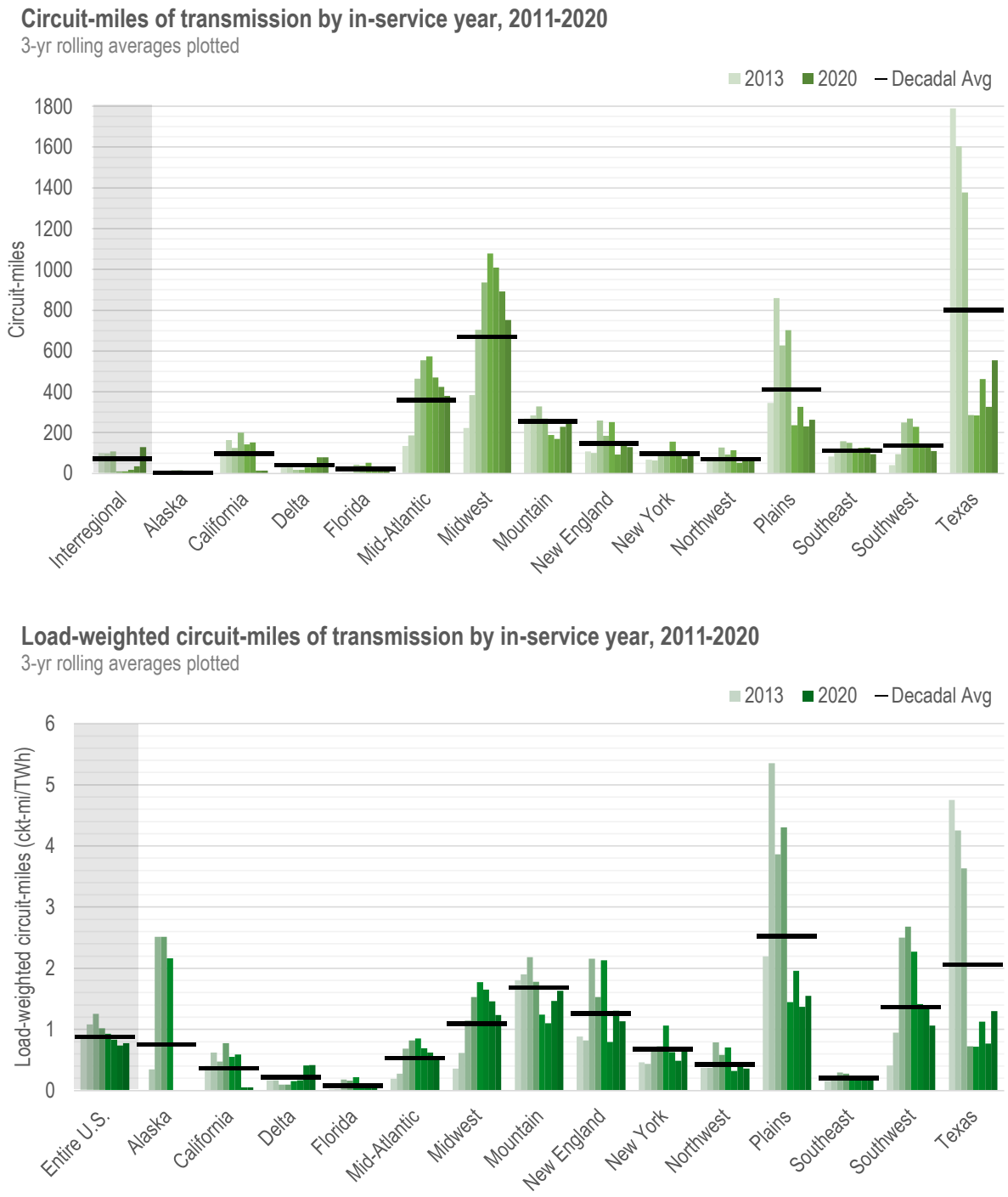
*Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c). Rounded to two significant figures.*




*Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c). All costs are adjusted to 2020 U.S. dollars using Consumer Price Index from Census (2022).*

*Note: Interregional costs are for projects that terminate in different regions, including international lines. Load-weighted costs for Entire U.S. encompass both regional and interregional lines.*

***Figure IV-1. Capital costs (top) and weighted by load (bottom) for new or rebuilt transmission lines (≥100 kV), shown as 3-year rolling averages. Horizontal lines are decadal averages.***




*Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c).*

*Note: Interregional circuit-miles are for projects that terminate in different regions, including international lines. Load-weighted circuit-miles for Entire U.S. encompass both regional and interregional lines.*

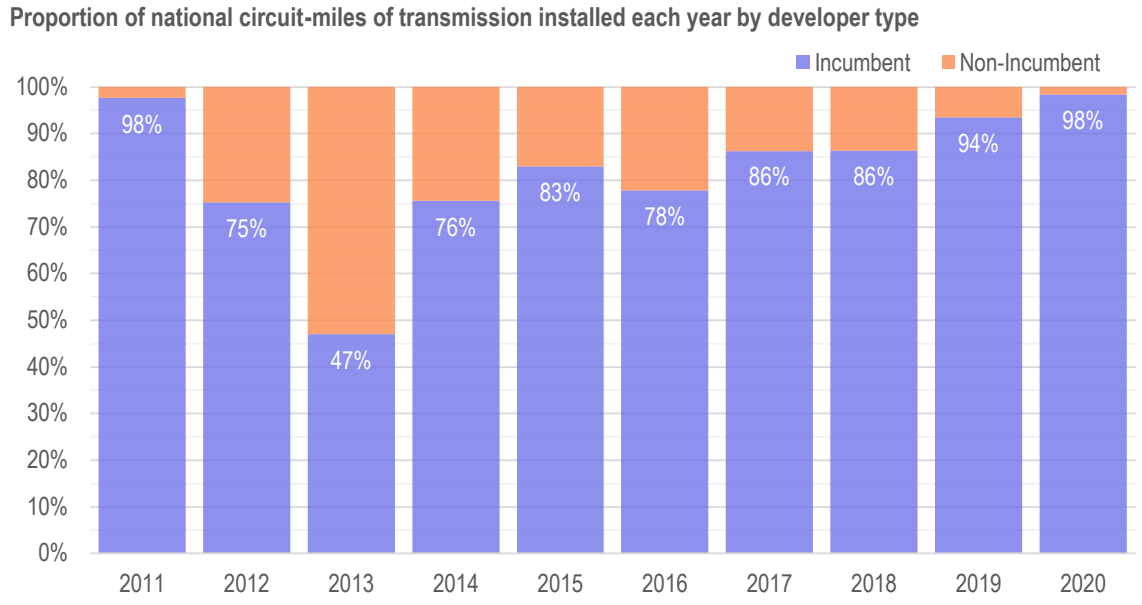
***Figure IV-2. Circuit-miles (top) and weighted by load (bottom) for new or rebuilt transmission lines (≥100 kV), shown as 3-year rolling averages. Horizontal lines are decadal averages.***

## Incumbent utilities installed the majority of transmission facilities

In addition to reviewing trends in total transmission investments, examining trends in who is installing transmission and why is also instructive. Figure IV-3 shows the proportion of new or rebuilt transmission (rated at or above 100 kV) circuit-miles energized each year between 2011 and 2020 by different developer type nationwide. Incumbent transmission developers, or entities that develop transmission within their own retail distribution footprint, have always dominated project development space nationwide. The proportion of project circuit-miles installed by non-incumbent transmission developers—or entities that do not have a retail distribution footprint or that are public utilities developing transmission outside of their footprint—was 25% or less every year of the last decade, with the exception of 2013 when non-incumbent developers were responsible for just over half of all projects energized that year.

Figure IV-4 shows the proportion of new or rebuilt transmission by different developer types by region. Interregional transmission between any two regions is also shown in the figure. (The total transmission circuit-miles installed in each region is shown in Figure IV-7 for reference.) Non-incumbent developers installed the most historic transmission in the Midwest, Plains, and Texas regions. These three regions dominate the national trends shown in Figure IV-3.

Figure IV-5 shows the total circuit-miles of new or rebuilt transmission energized each year by both developer type and nominal voltage rating. Incumbent developers installed more circuit-miles of transmission than non-incumbent developers across all years and voltage classes, except for in the 301–400 kV range in 2013 when installations were equivalent between the two groups. Non-incumbent developers predominantly installed projects in the 301–400 kV range, with some installations at lower voltage ranges. Very few projects higher than 500 kV were installed by any developer in the last decade.



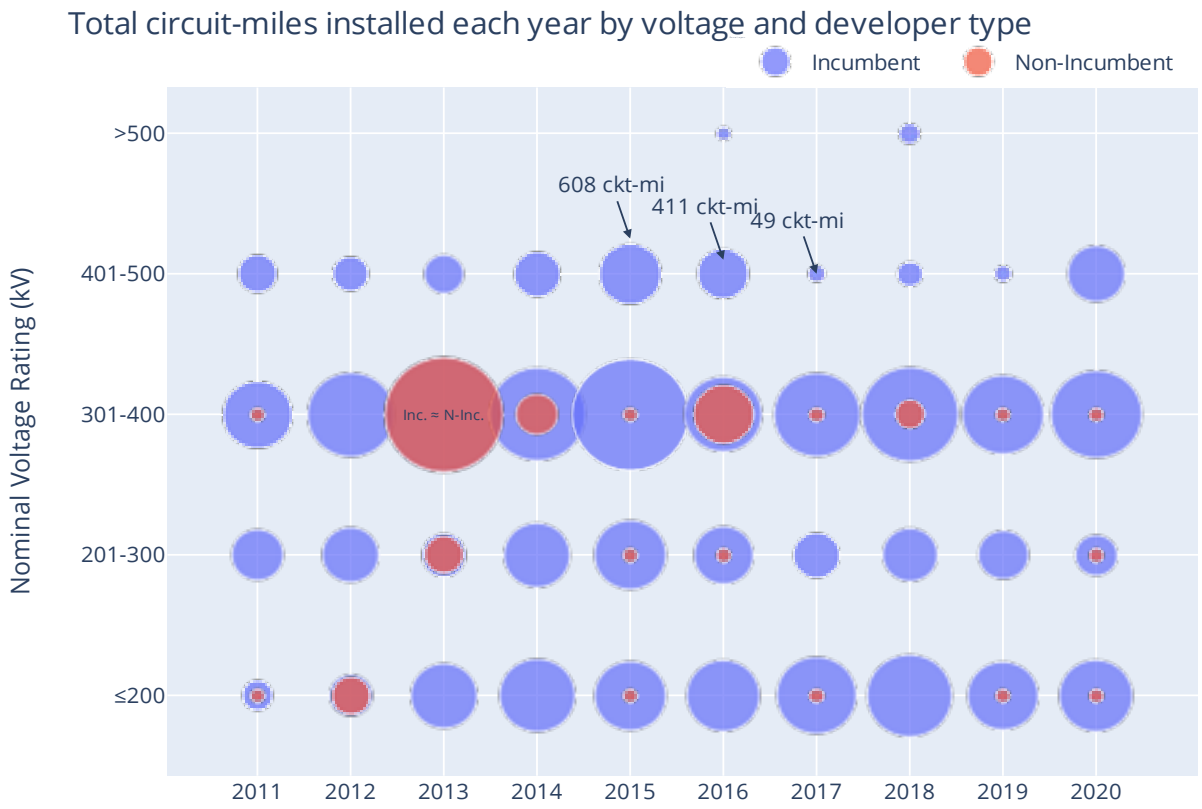

*Source: Data from MAPSearch Transmission Database (2023).*

***Figure IV-3. Proportion of national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project developer type.***

*Source: Data from MAPSearch Transmission Database (2023).*

*Note: Circuit-miles of transmission put in service each year shown in Figure IV-7. Alaska data are not shown due to few years of transmission builds. All Alaska builds were performed by incumbent developers.*

***Figure IV-4. Proportion of regional and interregional circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project developer type.***




*Source: Data from MAPSearch Transmission Database (2023).*

*Note: Size of markers indicate total national circuit-miles in each category. Values are explicitly shown for incumbent projects rated between 401 and 500 kV in 2015, 2016, and 2017 for reference. Both incumbent and non-incumbent developers installed equivalent circuit-miles of transmission rated between 301 and 400 kV in 2013.*

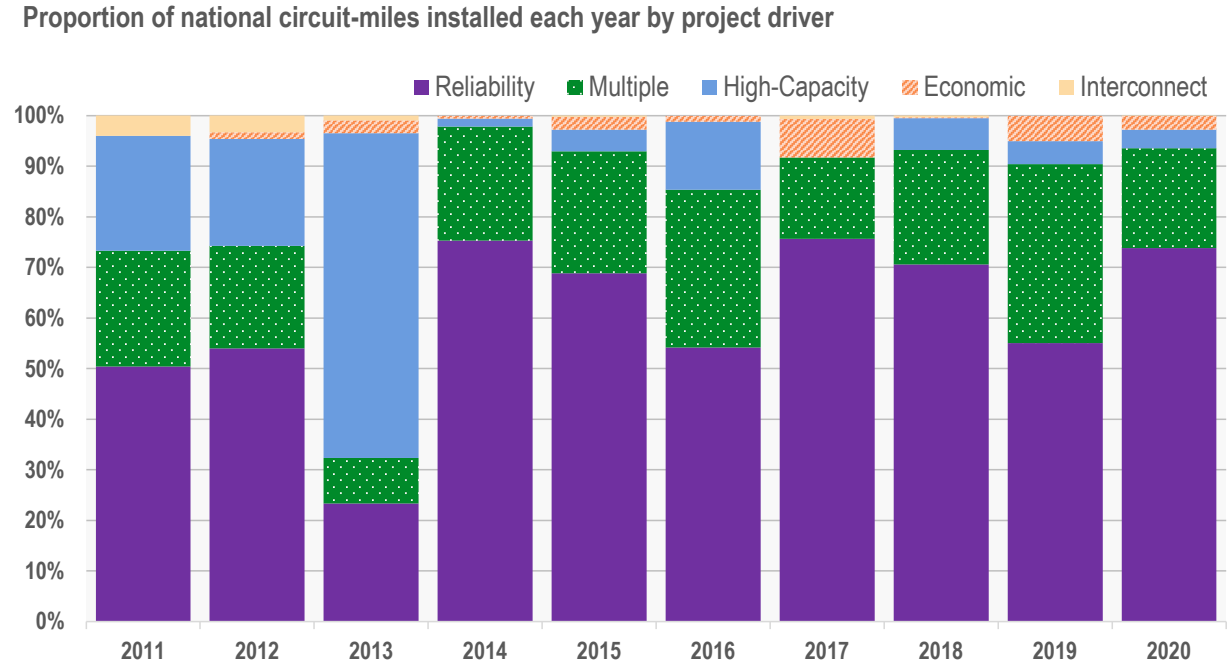
***Figure IV-5. Total national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by voltage rating and project developer type.***

## Specific reliability needs were the primary driver of transmission investments in most regions

Figure IV-6 shows the primary driver for all new or rebuilt transmission lines (rated at or above 100 kV) energized between 2011 and 2020 across the United States. New transmission projects can be a response to a single or a combination of drivers (*multiple*), including a specific reliability need (*reliability)*, the opportunity to realize production cost savings (*economic*), and the ability to interconnect new generators to the power system (*interconnect*), especially when moving generation long distances over high-capacity power lines, predominantly rated at or above 230 kV (*high-capacity*). The primary driver for a project is identified in transmission planning studies and can be used for cost allocation purposes.

The proportion of overall transmission circuit-miles installed to address specific system reliability needs has grown with time, from 50% in 2011 to 74% in 2020. Economic projects have always had a relatively low share of installed circuit-miles, making up just under a tenth of all projects at their peak in 2017. Projects meant to connect generation resources to the grid at

lower voltages have maintained a consistently small proportion of all projects. Lower voltage tie-line projects installed by generation owners to connect their power plants to the nearest available grid substation may not be fully captured in the database used. The proportion of circuit-miles installed to provide high-capacity transmission for connecting generation sources to the grid at high voltages (at least 230 kV) made up 64% of all projects energized in 2013. Projects installed primarily for this purpose dropped precipitously after that year and few circuit-miles have been energized since. The proportion of projects installed nationwide to provide at least two of these drivers was relatively constant—between 20% and 35% most years—over the past decade.




*Source: Data from MAPSearch Transmission Database (2023).*

*Note: **Reliability** projects are needed to improve the current state of the region's electrical grid. **Economic** projects refer to projects that reduce production costs and lower transmission system congestion or are associated with non-incumbent developers to lease transmission capacity to utilities. **Interconnect** projects connect power generation facilities to the transmission system, regardless of fuel source. **High-capacity** projects are interconnect projects that use higher voltage transmission (at least 230 kV) to connect generation facilities to the grid. **Multiple** projects are those projects that are driven by at least two of the above drivers.*

***Figure IV-6. Proportion of national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project driver.***

There are many factors contributing to changes in transmission development throughout the decade. These include state renewable portfolio standards that drove a change of generation from fossil fuel to renewables, transmission expansion to connect those renewables to the bulk electric system, and a strong economy to support the development. Additionally, the Energy Policy Act of 2005 (EPACT 2005) encouraged construction of more renewable resources with tax incentives, particularly for wind and solar, that provided financial support for utilities and others to build clean and renewable generation.

FERC Orders were also influential. Many orders prior to the year 2011 (i.e., 888, 889, 2000, 2003, 2006, 741, 745) drove the creation of wholesale markets and generation competition, which subsequently drove transmission needs. FERC Order 1000 in 2011 directly impacted transmission investments by providing for enhancements to the transmission planning and cost allocation requirements adopted in earlier FERC orders, notably requiring development of regional transmission plans and consideration of alternatives, consideration of transmission needs driven by public policies, and non-incumbent developer reforms.

Inspecting the regional variations in transmission drivers is insightful. Figure IV-7 shows the total circuit-miles of transmission energized each year from 2011 to 2020 in each region. Regional analysis shows that the large proportion of high-capacity projects energized nationwide 2011–2013 (*see* Figure IV-6) were installed almost exclusively in Texas. These projects were installed to enable large amounts of low fuel cost generation identified as part of the Texas Competitive Renewable Energy Zone initiative (NREL 2016).

High-capacity projects energized after 2013 were predominantly installed in the Plains, Southwest, Mountain, and California regions. These transmission lines tell a similar story to the high-capacity lines installed in Texas, namely that the majority of them were installed to interconnect clean energy resources to these regions (e.g., the Palo Verde nuclear facility in the Southwest and Windspeed II in the Plains), access low-cost fuel sources, increase generation portfolio diversity, or meet state clean energy goals.

Economic projects are driven by economic considerations, such as alleviating congestion on the grid that increases prices to consumers. These projects were installed primarily in the Mountain, Midwest, Southwest, and Texas regions. These projects were almost exclusively installed by incumbent developers in the second half of the decade.

*Source: Data from MAPSearch Transmission Database (2023).*

*Note: The scale of circuit-miles shown on the y-axis changes with each row of charts, obscuring the scale of projects relative to other regions. All interregional projects are grouped together and shown separately from regional projects. Project drivers are described in the caption of Figure IV-6.*

***Figure IV-7. Regional circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project driver.***

The Midwest region made sustained investments in projects driven by multiple purposes from 2015 through 2020. Many of these are from the 2011 Multi-Value Project Portfolio, which was a consolidated transmission planning process led by Midcontinent Independent System Operator (MISO) and the states to identify a portfolio of projects that together would deliver multiple benefits and provide regional value (delivering benefits that exceed costs across the region) in meeting economic, reliability and public policy needs (MISO 2012). MISO recently completed a second similar multi-benefit, portfolio-based, transmission planning process, called the Long-Term Regional Transmission Plan (LRTP). The Plains and Mountain regions—and to a lesser extent, the Southwest, Southeast, and Mid-Atlantic regions—also had several years of projects placed in service to meet multiple drivers.

**DOE Work on Transmission Financing**

The Department's Transmission Facilitation Program—authorized by IIJA Section 40106—is an innovative revolving fund program that will help overcome the financial hurdles facing large-scale new transmission lines, upgrades of existing transmission lines, and the connection of microgrids to existing infrastructure corridors in Alaska, Hawaii, and U.S. territories. Additionally, the Department's Transmission Facility Financing Program—authorized by IRA Section 50151—is a direct loan program for financing transmission projects located within National Interest Electric Transmission Corridors.

Dept. of Energy, Grid Deployment Office, Grid and Transmission Program Conductor Guide, https://www.energy.gov/gdo/grid-and-transmission-program-conductor-guide.

The greatest diversity of transmission project drivers is attributed to the Mountain, Midwest, and Texas regions. The New England, New York, Delta, and Florida regions had the least diversity, installing reliability projects almost exclusively. Interregional projects were also almost exclusively driven by reliability needs.

## IV.b. Market Price Differentials

Wholesale electricity prices from the seven RTO/ISO energy markets can be used to identify regions that would benefit from additional transmission resources. Prices within these wholesale electricity markets are determined at locational marginal price nodes allowing prices to vary depending on local conditions. Nodal prices are divided into three constituent parts: energy, losses, and congestion. The energy component is constant at all nodes within a single market, but the losses and congestion components vary by location. The cost of losses is small, which means that price variation by location within each market is driven primarily by transmission system congestion.

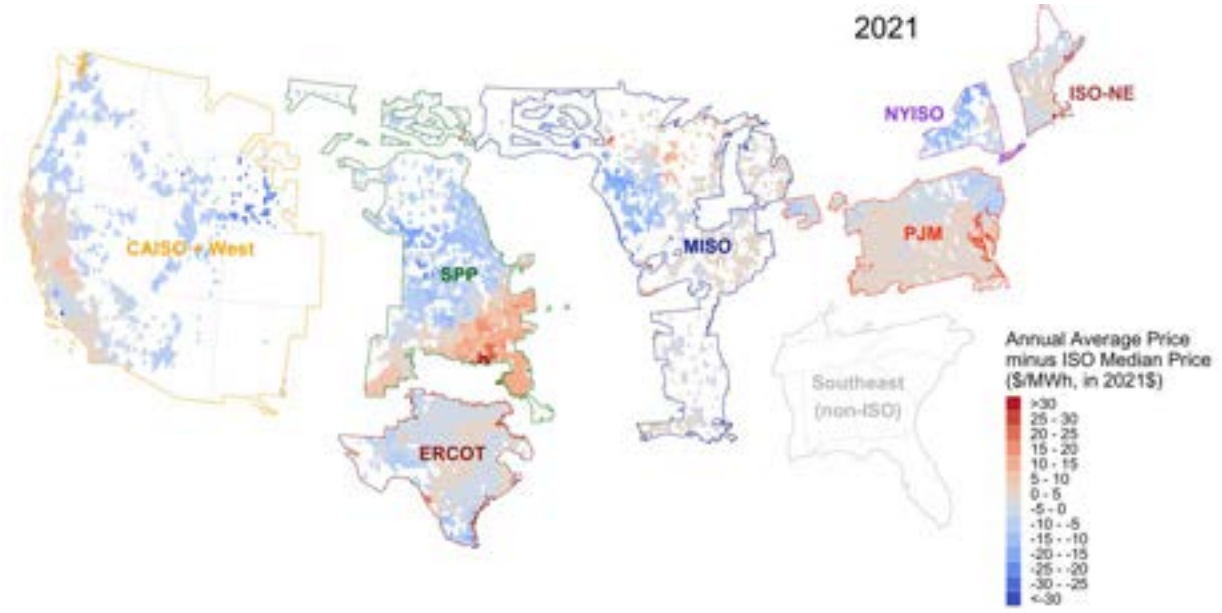
This analysis builds on past work. FERC (2017) identified that price differentials could identify insufficient transmission between locations and DOE (2020) examined congestion in wholesale markets using RTO/ISO-reported congestion costs. These reports presented congestion costs

only at the regionwide level; as a result, they do not provide insight on where congestion is most costly within each region, nor do they provide insight on the value of interregional transmission. Additionally, RTO/ISO-reported congestion metrics are challenging to compare to each other because each RTO/ISO has a different approach for calculating these metrics. DOE (2020) also examined transmission line usage rates in the western United States, finding high usage on some transmission lines. This market price analysis goes beyond past work by analyzing and identifying congestion across all nodes within each region and providing a metric to examine the value of interregional transmission. In this analysis, price differences within and across energy markets were examined to understand trends in congestion and the implications for transmission expansion. The analysis reported here as well as additional details can be found in Millstein et al. (2022a) and (2023).

## Regional price differences highlight locations of persistently high electricity prices

Congestion has created gradients in electricity prices across each major wholesale market region. These spatial gradients can be observed in Figure IV-8, which shows how the 2021 annual average price at each node differs from the median annual average price across all nodes in a region. For example, prices are low in northern and high in southern Plains region (SPP), prices are low in western and higher in eastern Midwest (MISO), and prices are low in the eastern portion of the Mountain (CAISO + West) region,[33] but higher in California, especially near population centers. A north/south pricing gradient in New York (New York Independent System Operator, NYISO) and New England (New England Independent System Operator, ISO-NE) is also apparent. New transmission between these and other low- and high-priced regions would allow load in high-priced markets to draw energy from a larger set of generators and lower electricity costs in high-priced regions. The extent to which high prices could be reduced depends on the magnitude of available generation made accessible by the new transmission. Goggin (2021) explores the potential for interregional transfer during recent extreme weather events, such as the February 2021 cold weather event (frequently referred to as Winter Storm Uri). Goggin (2021) finds that while transfer across regions would have been limited by lack of available generation during certain hours, substantial transfers across existing lines did help to limit price spikes in multiple regions and additional transmission capacity would have allowed for even greater reduction to price spikes during many extreme weather events.

[33] Wholesale electricity price datasets are not readily available for the non-RTO/ISO West and can create challenges in evaluating congestion along the eastern edge of the Western Interconnection. See Section V.b. for further discussion.




*Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).*

*Note: Each RTO/ISO is treated as a separate region, except CAISO and the larger western region, which are treated as a single region. Nodal price analysis does not provide full geographic coverage of congestion through the non-RTO/ISO western region (particularly in New Mexico and Colorado but also in portions of other states). Similarly, the analysis provides no coverage of non-RTO/ISO regions in the Southeast. Also, note that small price differences of $0–$5/MWh may be due to losses rather transmission congestion.*

***Figure IV-8. Price difference between nodal average price and the regional median price in 2021.***

An alternative approach to defining congested regions is to identify locations with price spikes (noticeably high or low hourly prices relative to prices across a region). Of particular interest are locations that have large price spikes across many years, which could indicate insufficient transmission infrastructure (FERC 2017), or insufficient local generation. To determine locations with consistent price spikes, we used another approach FERC developed—the Market Price Differential metric (FERC 2017). The Market Price Differential metric highlights locations with persistently low- or high-price spikes over many years.[34]

In contrast to the price gradients shown in Figure IV-8, the Market Price Differential metric shows only a subset of all nodes, which allows identification of discrete locations that would benefit from transmission. For example, Figure IV-9 shows discrete pockets of low- and high-priced nodes across the eastern region. Of particular note are the low-priced pockets centered on the Oklahoma and Kansas border in the Plains, collocated with substantial wind resources. Similarly low-priced pockets can be found near wind resources in the Midwest in Iowa and Minnesota, and in the Mid-Atlantic in Illinois. High-priced regions are identified in New York City and Long Island, in the Mid-Atlantic near Washington, DC, and in the eastern Plains region. A full list of high- and low-priced regional "pockets" is presented in Table IV-2. Additional transmission to bring cost-effective generation to demand in any of these high-priced locations

[34] More information on the methods used here and summary data are available in the Supplemental Material.

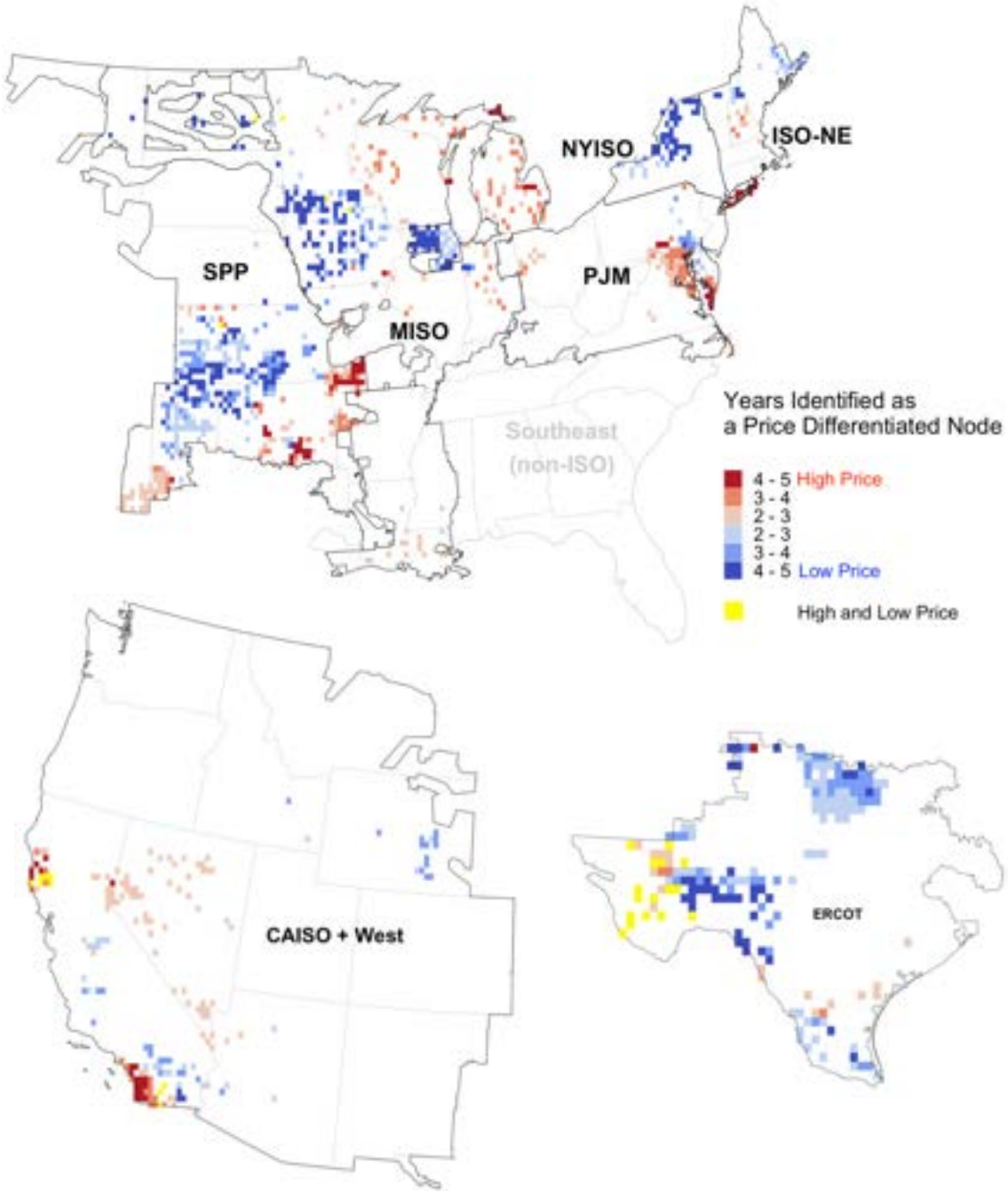
would help lower prices in those regions. Other strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices. The specific solutions that work for each locality might be unique to that community.

Note that Figure IV-8 combines the RTOs/ISOs in the Eastern Interconnection. Alternatively, one can calculate the Market Price Differential metric within each RTO/ISO individually. Doing so largely identifies the same set of congested nodes as the interconnection-wide calculation depicted in the figure.[35] That the pattern of congested locations does not meaningfully differ between the individual RTO/ISO analysis and the combined region analysis suggests that the extreme prices in each RTO/ISO remain extreme within the context of the entire Interconnection.

The western region has fewer congested areas identified by the Market Price Differential metric (*see* Figure IV-9) compared with the many different pockets of congestion identified across the Eastern Interconnection. For the non-RTO/ISO West (Northwest, Mountain, and Southwest), however, this observation is more a function of lack of wholesale electricity price data than a depiction of actual operating conditions. Most notable is the congestion that limits energy transfer into the populated area along the southern coast of California from the nearby inland region east of the coast. Additional congestion is observed in coastal northern California and in Wyoming. There is some additional indication of congestion in Nevada, but this is found for only 2 out of 5 years, in most cases. We note that geographic coverage of the western region is sparse for the metrics shown in Figures IV-8 and IV-9. Additional analysis of congestion in the western region is discussed in Section IV.c.

Pockets of congestion are also identified in the Electric Reliability Council of Texas (ERCOT; *see* Figure IV-9). In Texas, low-price regions are identified in the northern, western, and southern areas of the state. Few high-priced nodes are identified to be consistently high priced for more than 2 years. This indicates that the location of high-priced nodes has varied by year in Texas, while low-cost nodes have been more consistent over time.

[35] See Supplemental Material for a comparison between the calculations when each RTO/ISO is considered in isolation.




*Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).*

*Note: The Market Price Differential metric was calculated while treating the Eastern Interconnection as a single combined region (RTO/ISO boundaries are provided for reference). The metric is calculated independently each year; nodes are highlighted when they are identified for 2 or more years. Only a subset of nodes is identified as high- or low-priced nodes, and white space indicates either no nodes in that location or existing nodes were not identified as high- or low-priced (for reference, Figure IV-8 shows all nodes). The yellow color represents nodes that contained at least 2 years identified as high-priced and 2 years identified as low-priced.*

***Figure IV-9. Low- and high-priced nodes identified by the Market Price Differential metric between 2017 and 2021. Top: RTOs/ISOs within the Eastern Interconnection. Bottom left: CAISO and the WEIM. Bottom right: ERCOT.***

***Table IV-2. High- and low-priced areas identified within the wholesale markets of the three Interconnections. Regions are defined based on a regional concentration of nodes identified with the Market Price Differential metric.***

| Region | Low-Priced Areas | High-Priced Areas |
|---|---|---|
| **Plains** | Southern and Western KS<br>OK/TX Panhandles | Southern OK<br>Southwest MO |
| **Midwest** | Southwest and Central IA<br>Southern MN | Northwest WI<br>Eastern and UP MI |
| **Mid-Atlantic** | Northeast IL<br>Southeast PA | Eastern MD/VA<br>Delmarva Peninsula MD & DE |
| **New York** | Upstate NY | Long Island NY |
| **New England** | North VT/NH | – |
| **California** | Mojave Desert CA | Southern Coast CA<br>Northern Coast CA |
| **Mountain** | Eastern WY | – |
| **Texas** | Northern TX<br>Western TX<br>Southern TX | – |

## Interregional price differences suggest large value in cross-interconnection transmission to alleviate harmful congestion

Although the regional calculation of the Market Price Differential metric (*see* Figure IV-9) provided some indication of the need for interregional transmission, we can more directly assess the value of transmission across regions and interconnections by determining the average hourly difference in pricing between regional hubs. One indicator of the value of new transmission is the energy arbitrage potential, that is, the difference in price between two locations.[36] Transmission provides additional value not included within this energy arbitrage value, such as providing capacity value, improving grid reliability and security, helping reduce emissions by facilitating greater deployment of wind and solar resources, and improving resilience to extreme weather and unexpected events. The energy arbitrage value is also a marginal value, meaning that as transmission capacity is added to the system, the value would decline. Nevertheless, the energy arbitrage value can be an important measure of transmission value and provides an approach for ranking the value of different potential transmission connections. It is important to note that the value indicated by energy price arbitrage is indicative of value to certain market participants, but it is different from the approach that RTOs/ISOs use to measure potential new transmission value (i.e., using forward looking models to estimate production cost savings).

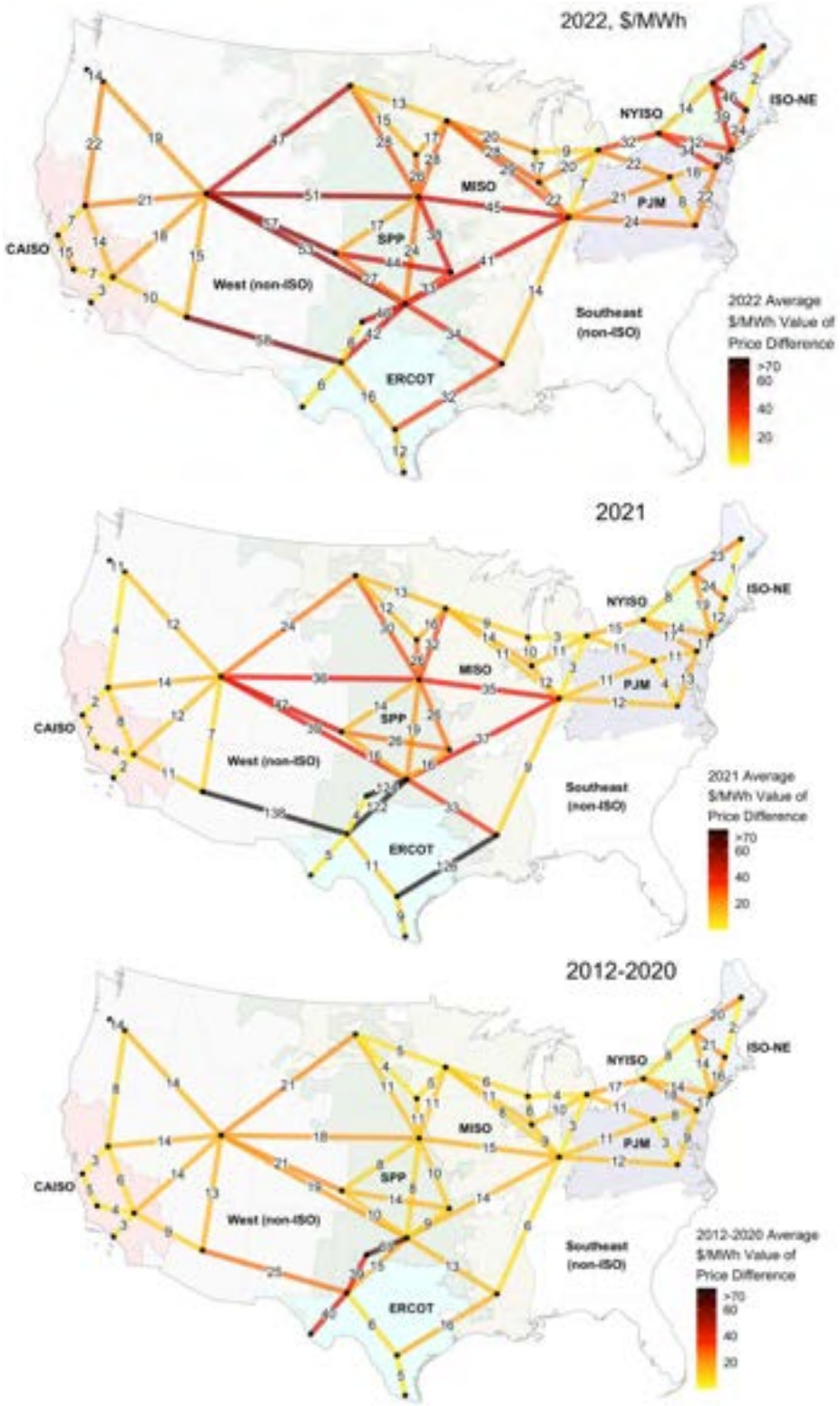
Figure IV-10 shows the average hourly difference in energy price between a selected set of pricing nodes. Selected nodes were “hub” or “zonal” nodes, as those nodes were most representative of the larger region. Specifically, these nodes represent an aggregation of regional buses and generally represent more ‘liquid’ market conditions. A high marginal value of transmission either within or between regions indicates additional, strategically placed

[36] Large hourly price differences across regions suggest transmission value but do not perfectly quantify the marginal transmission energy value between regions because market rules for nodal price formation vary by region. Thus, results here should be interpreted as suggestive, but not a definitive measure of value.

transmission would reduce system congestion and constraints. Transmission between RTOs/ISOs was generally more valuable than transmission within RTOs/ISOs. In 2022, 2021, and on average between 2012 and 2020, the highest value links were between SPP (Plains region) and its neighbors, between ERCOT (Texas region) and its neighbors, and across the northeastern regions (New England, New York, Mid-Atlantic). Exploring the time trends of these links reveals that the value of interregional transmission to SPP and to ERCOT has been increasing over time.[37]

The marginal value of transmission increased substantially in 2021 and then again in 2022 compared with prior years (e.g., compare the three panels of Figure IV-10). This increase broadly tracks the overall increase in energy prices observed since 2021. Compared with the 2012–2020 average, 2022 saw broad increases in transmission value across all regions (Millstein et al. 2023). In many locations, values in 2021 were similar to values in 2022, except for the impact of extreme weather. For example, average nodal electricity prices in Texas and the Plains were 3.9 and 1.9 times higher in 2021 than in 2019, respectively (2021 is compared with 2019 rather than 2020 to avoid comparison with the low 2020 prices caused by the COVID-19 pandemic). In other regions, 2021 electricity prices increased by 1.5 times or less between those same years (the increase was only 1.2 times in California). Thus, it is not surprising that the 2021 value of transmission between the Plains and other regions, and the value between Texas and other regions, increased by more than the increase seen between the remaining U.S. regions.

[37] Further analysis of time trends is presented in the Supplemental Material and in Millstein et al. (2022a).




*Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b and 2023).*

***Figure IV-10. Average hourly difference in price between selected hub and zonal nodes within and across regions for 2022 (top), 2021 (middle), and for 2012–2020 (bottom).***

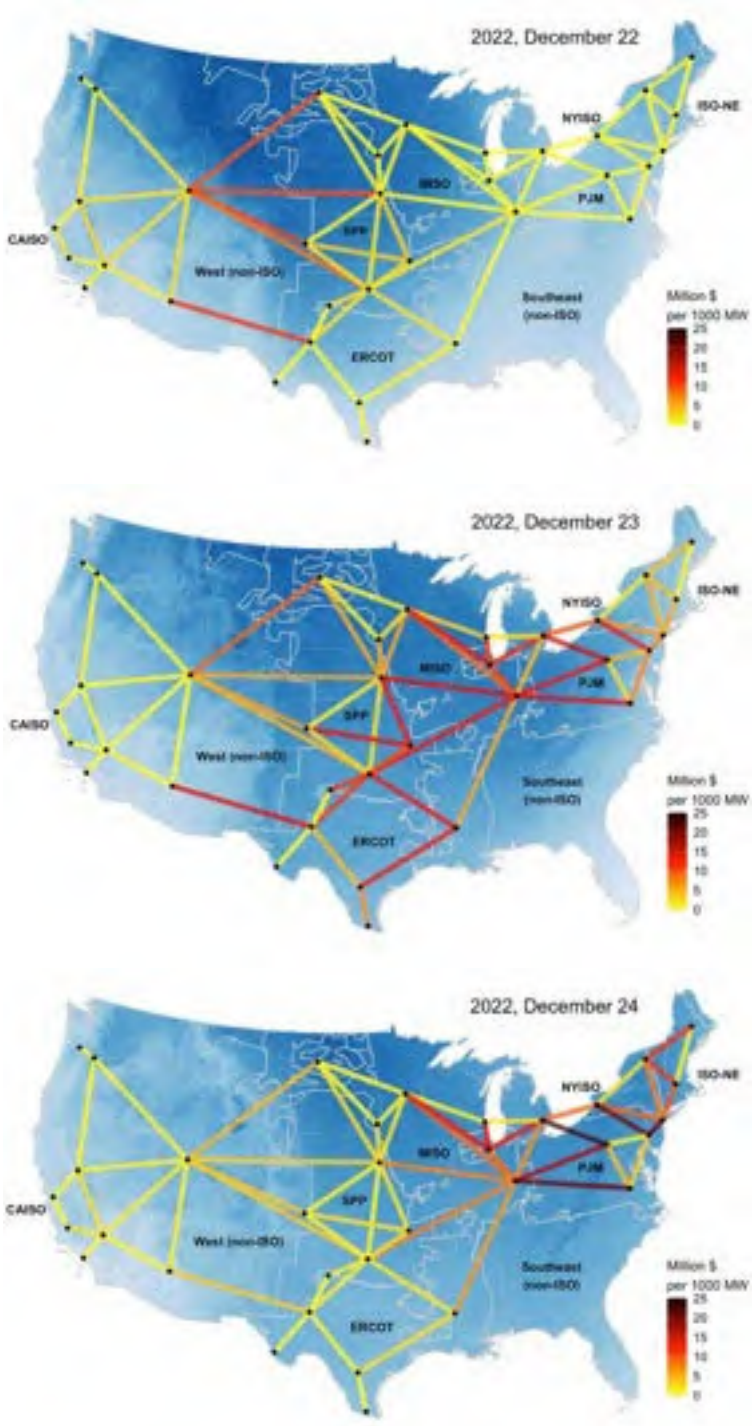
## Highest transmission congestion value is concentrated in only a few hours of the year and during extreme events

Transmission value can be affected by relatively infrequent but challenging conditions on the electricity system. Examples of these conditions include fluctuations in uncertain variables for either short-term or long-term periods (e.g., fuel-price volatility, inaccurate demand forecasts, inaccurate renewable forecasts), extreme weather events (e.g., heat wave, winter storm), exceptional levels of electricity demand, and infrastructure failures (in transmission or generation equipment, for example). Correlation of the above conditions can lead to particularly high system congestion.

In the Plains and Texas, extreme weather (e.g., Winter Storm Uri) produced a price spike in February 2021 (Levin et al. 2022). This period was characterized by extremely high prices in these two regions—in the thousands of dollars per megawatt-hour (MWh)—which were not observed in neighboring regions.[38] The period of extreme prices in February 2021 was limited primarily to the Plains and Texas and demonstrates an important value of transmission: the ability to address regionally concentrated extreme weather impacts on electricity prices. The high prices found in Texas in 2021 may also have been reduced had certain regulatory changes already been implemented, including requirements for weatherization for generation resources and lower peak price limits. While 2021 reflects discrete, high-cost events in the Plains and Texas, other regions would benefit less from interregional investment in the face of similar events, which are expected to become more frequent.

Similarly high interregional transmission value resulted from Winter Storm Elliot in December 2022. Cold weather associated with the winter storm moved eastward across the country over the multiday storm, which is reflected in the daily transmission values between nodes (*see* Figure IV-11). High average hourly prices between nodes were first found between the three Interconnections on the first day of the storm, then shifted to nearly all regions in the middle of the country—Plains, Midwest, Texas, Delta, western Mid-Atlantic—on the second day, until finally impacting the northeastern regions—New England, New York, eastern Mid-Atlantic—on the third day. Additional discussion and details can be found in Millstein et al. (2023).

[38] Wholesale price patterns can be investigated with the Renewables and Wholesale Electricity Prices tool, see Millstein et al. (2022b).




*Source: Lawrence Berkeley National Laboratory (Millstein, et al. 2023).*

*Note: Transmission value is measured in cumulative daily million USD of a hypothetical 1000 MW transmission link between two nodes. Darker blue background colors reflect colder surface temperatures.*

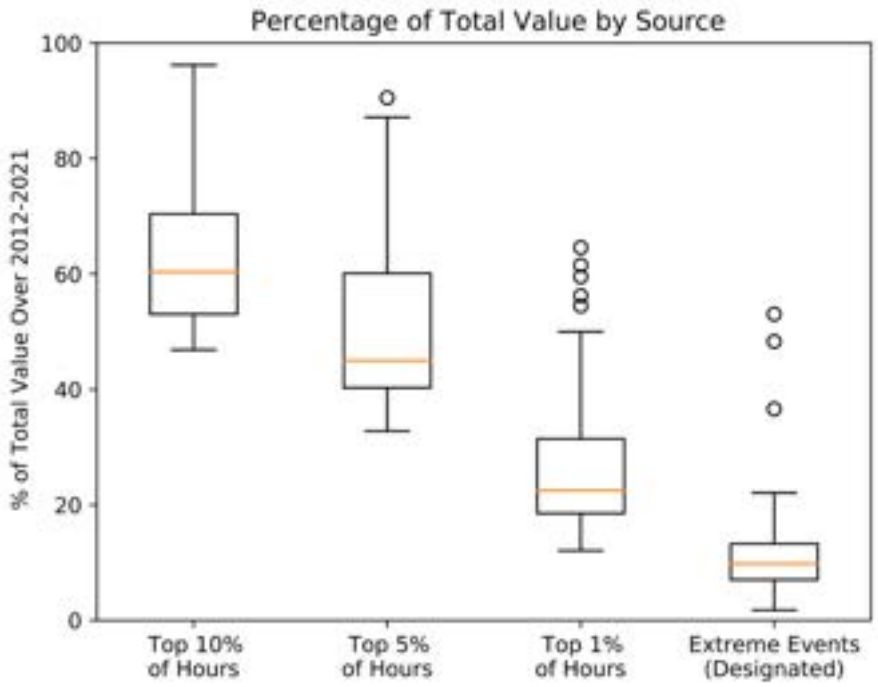
***Figure IV-11. Transmission value between selected regional nodes moved east with cold surface temperatures during December 22–24, 2022 (Winter Storm Elliot).***

In addition to scrutinizing price patterns during specific events, the portion of total transmission congestion value attributable to high-value hours or extreme conditions is analyzed here. Two approaches are used to identify extreme conditions or high-value hours: In the first approach, literature and NERC reports are used to identify specific time periods of grid stress and extreme weather events.[39] Congestion value over these types of events is tabulated and together the events are referred to as "designated events." In the second approach, the value at each potential transmission link is calculated each hour and ranked, and the portion of total value contained in the top 1%, 5%, and 10% of hours (sorted by value) is tabulated. This second approach assumes that, although there was not necessarily a named weather event or infrastructure outage during all these top hours, the very fact that the price differential is so high indicates that an infrequent set of conditions exists. These conditions may not require emergency action by the RTO/ISO, and in fact may be an infrequent condition that occurs during standard operational conditions but occur during a period in which the market faces extreme price differences. The first and second approaches identify a somewhat overlapping set of hours, but the subsequent analysis is designed to prevent any double counting issues where relevant.

For each transmission link as established in Figure IV-10, the total value over the study period was calculated, along with the value of the top 10%, 5%, and 1% of hours (in which these hours have been determined separately for each link). An important finding here is that a small portion of hours accounts for roughly half the value. Specifically, in the median case, the top 5% of hours account for ~50% of value (*see* Figure IV-12). The top 1% of hours account for 20% to 30% of total value. Designated extreme events produce 10% to 20% of value (and account for ~5% of total hours). This indicates that many of the most valuable hours for transmission fall outside the set of designated extreme events, and instead occur during more standard operational conditions that were not flagged in the process used to designate extreme events.

Overall, this analysis highlights the importance of properly representing challenging grid conditions, including explicitly representing extreme weather events, fuel-price volatility, generation and load uncertainty, and geographic market resolution, when estimating or modeling the congestion value of transmission. Doing so is critical to ensuring that the value of transmission investments in alleviating congestion and constraints that are negatively impacting consumers is accurately accounted for in planning. Failing to account for these grid conditions, or using an inaccurate snapshot of time to determine the value of transmission, will result in transmission plans that do not address the negative impacts of congestion and constraints over time. Additional discussion and details can be found in Millstein et al. (2022a).

[39] Details can be found in (Millstein et al. 2022a).




*Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022a).*

*Note: The distribution reflects the spread across the set of links shown in Figure IV-10. Designated "extreme events" include 171 event days between 2012 and 2021 defined in Millstein et al. (2022a)*

***Figure IV-12. The portion of transmission congestion value derived from selected conditions over 2012–2022.***

## IV.c. Qualified Paths

For the non-RTO/ISO Western Interconnection, evaluating congestion can be a challenge because of a lack of wholesale electricity price data. Instead, information on congestion management, particularly along the eastern edge of the Western Interconnection, can be obtained from transmission system operators and The Western Electricity Coordinating Council (WECC).

When congestion occurs along the West Coast, which can be frequent as demonstrated by the Market Price Differential analyses in Section IV.b., unscheduled energy from the Northwest flows through Wyoming, Colorado, New Mexico, and Arizona. This energy flow, referred to as loop flow, can create significant congestion and reliability challenges along the eastern edge of the Western Interconnection (*see* Figure IV-13). In response, the Western Interconnection uses the WIUFMP. The WIUFMP is a FERC-filed tariff that provides a mechanism for reliability entities to mitigate flows on Qualified Paths to reliable levels.[40]

Qualified Paths in the West designate transmission with the highest levels of congestion. Four of the approximately 50 paths in the Western Interconnection were identified as qualified

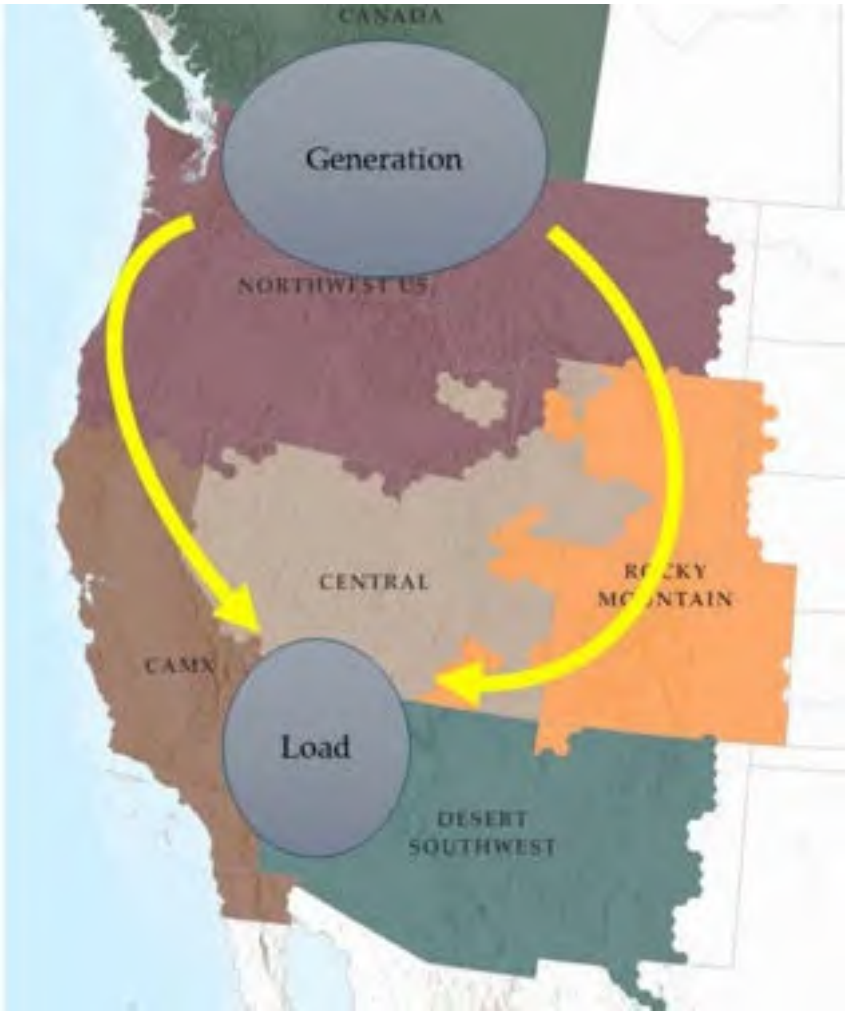
[40] The WIUFMP FERC tariff is available at https://spp.org/documents/62460/081919%20wiufmp%20tariff.pdf.

paths. Path 66 (California), Path 36 (Wyoming-Colorado), Path 30 (Colorado-Utah), and Path 31 (Southern Colorado-Northern New Mexico) are bottlenecks of limited transmission to deliver power from the Northwest to the highly populated Desert Southwest (SPP 2020). These paths are listed in Table IV-3. Figure IV-14 shows these paths and many major paths in the Western Interconnection.[41] The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can create reliability risks. Additional, strategically placed transmission deployment would alleviate unscheduled flows on Qualified Paths. Historically, the West has leveraged specific phase-shifting transformers, also referred to as Qualified Controllable Devices, to redirect flows to manage unscheduled flow.

Phase shifters were a cost-effective alternative to additional transmission for many years, but their effectiveness is decreasing as the industry transitions away from tradition thermal generators to renewable energy resources. Much of the existing high-voltage transmission system was constructed around thermal generators. Utility-scale renewable resources are in different locations relative to existing transmission infrastructure, which has implications for transmission loading and can create incremental unscheduled flows on certain transmission segments, including the qualified paths.

In addition to the phase shifters, thermal generators have traditionally been leveraged as tools to manage congestion. Generator output can be increased or decreased on either side of affected transmission segments, which can aid in alleviating constraints. Given the number of thermal generator retirements, incrementing and decrementing generation is not as available as a tool for congestion management. This lack of availability increases the reliance on the phase shifters, which were not designed to manage the changes in transmission flows developing on the system.

[41] Stakeholders have also independently assessed congestion on other major paths within the Western Interconnection. CAISO, for example, has conducted a high-level investigation of major transmission congestions as part of its 2022-2023 Transmission Plan and has identified various additional WECC paths as constrained areas. *See* CAISO at https://www.caiso.com/Documents/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.




*Source: Western Electricity Coordinating Council (March 2021); https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.*

***Figure IV-13. Loop flow in the Western Interconnection.***

***Table IV-3. Qualified paths and path operators in the Western Interconnection.***

| Qualified Path | Path Location | Path Operator |
|---|---|---|
| Path 66 – California Oregon Interface (COI) | Southern Oregon, Northeast California, and Northwest Nevada border | CAISO |
| Path 30 – TOT1A | Northeast Nevada and Northwest Colorado border | Western Area Power Administration (WAPA) |
| Path 31 – TOT2A | Southern Colorado and Northern New Mexico border near Four Corners | WAPA |
| Path 36 – TOT3 | Southeast Wyoming and Northern Colorado border, north of Denver | WAPA |

*Source: Qualified Paths and path operators in the Western Interconnection from SPP at https://spp.org/documents/58826/current%20list%20of%20qualified%20devices%20&%20paths_062520.pdf.*

*Source: Western Electricity Coordinating Council; https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf.*

***Figure IV-14. Paths in the Western Interconnection.***

Additional transmission and expanded market structures to price and manage congestion are potential solutions to congestion challenges in the non-RTO/ISO West. The need for additional transmission capacity will become increasingly acute as transmission flow patterns continue to change because of additions of variable energy resources (VERs), thermal generator retirements, and drought-induced reductions in hydropower generation. Of critical importance is that changes made to the transmission system on the western edge of the Western Interconnection (CA, OR, WA) can have significant implications for transmission system operations on the eastern edge of the Western Interconnection (WY, CO, NM) because of the unscheduled loop flow described previously. This reliability and economic consideration is system wide. As the transmission system is expanded along the West Coast, transmission upgrades also might be necessary along the eastern edge of the Western Interconnection to protect system reliability across the entire West. Interconnection-wide power flow analyses and system impact studies will be essential in the study processes.

The non-RTO/ISO West faces unique challenges because it currently consists of 38 separate balancing authority (BA) areas as shown in Figure IV-15. BAs are NERC-registered entities subject to strict NERC requirements to balance supply and demand in their respective footprints in real time. They meet these demands through extensive manual coordination with generators and transmission owners/operators within their footprints, along with communications with neighboring BAs and the regional reliability coordinators. The RTOs/ISOs use a system known as Security Constrained Economic Dispatch to automatically adjust generation outputs in response to real-time system congestion, a base functionality not used by the BAs. The manual processes used in the non-RTO/ISO West to adjust generation were reasonably effective when net load (demand less variable generation) was straightforward to forecast. The fragmented BA model, however, is becoming increasingly difficult to manage. Automated economic dispatch procedures provided through CAISO's WEIM have partially addressed the difficulties in managing manual coordination between generators and transmission operators for WEIM participants in the Western Interconnection.

Another factor associated with the non-RTO/ISO West is that interregional transmission is exceptionally difficult to plan or develop because of a lack of centralized planning processes and codified cost allocation mechanisms. As a result, the transmission development that does occur is not optimized from a regional reliability or economic perspective.

*Source: Western Electricity Coordinating Council Maps of the Western Interconnection; https://www.wecc.org/ReliabilityModeling/Pages/Maps.aspx*

*Note: Boundaries are approximate and for illustrative purposes only.*

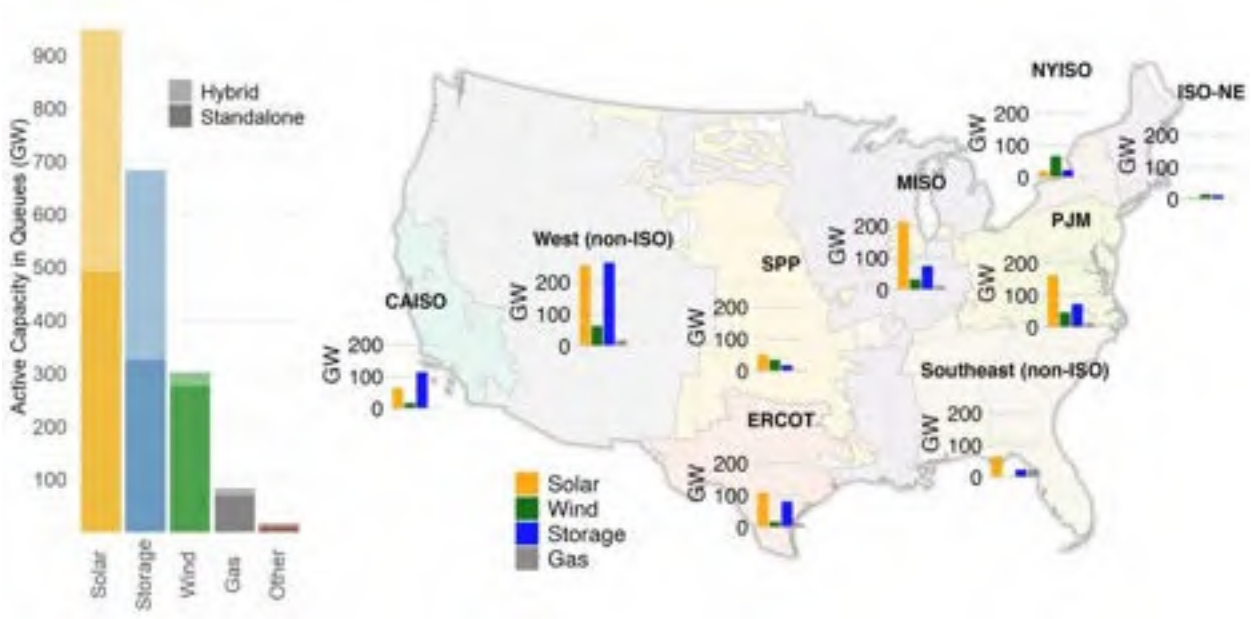
***Figure IV-15. Western Electricity Coordinating Council balancing authorities.***

## IV.d. Interconnection Queues

All generation requests must undergo a series of studies before connecting to the transmission system to ensure grid reliability will not be negatively impacted. Generators wait in line for these studies in interconnection queues. Data from generation interconnection queues also demonstrate the growing need for new transmission infrastructure.

The latest compilation of data from Lawrence Berkeley National Laboratory shows that a record amount of new generation and storage capacity has applied for interconnection (DOE 2022a; Rand et al. 2023). More than 2,000 Gigawatts (GW) was sitting in clogged interconnection queues at the end of 2022, the majority of which was solar and storage, but also included large amounts of wind and gas facilities (*see* Figure IV-16). The enormous amount of solar, wind, and storage in the interconnection queues demonstrates that market and economic trends will lead to continued shifts in the Nation's resource mix, requiring a different approach to transmission

planning and development. As discussed later (Section VI), studies have repeatedly shown that given the Nation's changing resource mix, a least-cost power grid requires enhanced transmission links within and among regions.




*Source: Data from Lawrence Berkeley National Laboratory; https://emp.lbl.gov/queues.*

*Note: Hybrid plants are those paired with one or more other type of generation or storage.*

***Figure IV-16. Power plants seeking transmission connection by type (left) and mapped to region (right).***

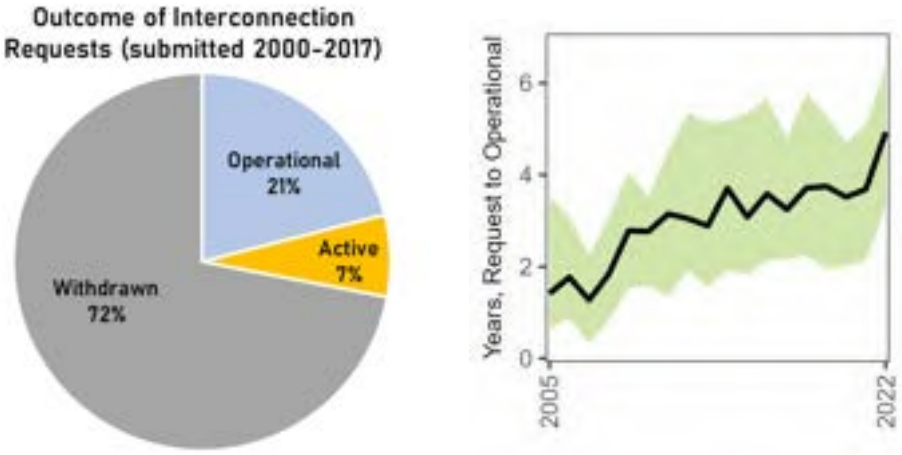
## Generation is waiting longer to connect to the transmission system

The duration between an interconnection request and commercial operation has increased. Among the regions with available data, the typical duration from an interconnection request to commercial operation was 5 years in 2022, compared with 3 years in 2015 and less than 2 years in 2008 (*see* Figure IV-17). The average duration from a request to a signed agreement has also increased in most regions and, on average, nationally for those regions where such data are available. High withdrawal rates are also evident: 72% of projects that sought interconnection between 2000 and 2017 subsequently withdrew their requests.

There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase. Some projects in the queues are speculative in nature, in part driven by uncertainty in the scope and cost of necessary transmission upgrades and the extended timelines associated with the current interconnection process—often leading prospective projects to submit an interconnection to obtain information, followed by withdrawals and successive restudies of other projects. Other challenges include securing land, permits, community support, power purchasers and financing, as well as unanticipated changes to project economics and available policy incentives. In addition, some projects enter and remain in the queues because of the lack of disincentive for doing so.

As such, these trends partly reflect strong growth in interconnection requests and a diversity of underlying project-level and queue management issues. Yet there is also recognition that trends in interconnection queues are impacted by limited existing transmission infrastructure and resulting transmission upgrade costs needed for interconnection that, in many cases, the interconnecting generator must bear (DOE 2022a). Specifically, developers often incur costs not only to connect to the existing transmission system but must also provide up-front capital costs needed to upgrade the broader, high-voltage transmission grid, which provides benefits to those behind them in the queue and to the users of the networked transmission system more generally. Interconnection costs are increasing, especially for these broader network upgrades (Caspary et al. 2021; Gorman et al. 2019). The specifics of cost allocation for these network upgrades vary regionally, but evidence is mounting that some of these network upgrades paid by interconnecting generators provide system-wide benefits (ICF 2021). Assigning the costs of these broader network upgrades to the first generator in line can cause those projects to drop out, even though those upgrades could facilitate additional interconnecting generators further down the queue.

As described in a recent FERC Notice of Proposed Rulemaking (FERC 2022), these challenges are partly related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests the piecemeal approach to transmission deployment occurring with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process. FERC notes that improved transmission planning and additional investment in the bulk power transmission network will be needed to optimize the overall power grid and would be an effective means to address the increasingly long interconnect queue times (FERC 2022).

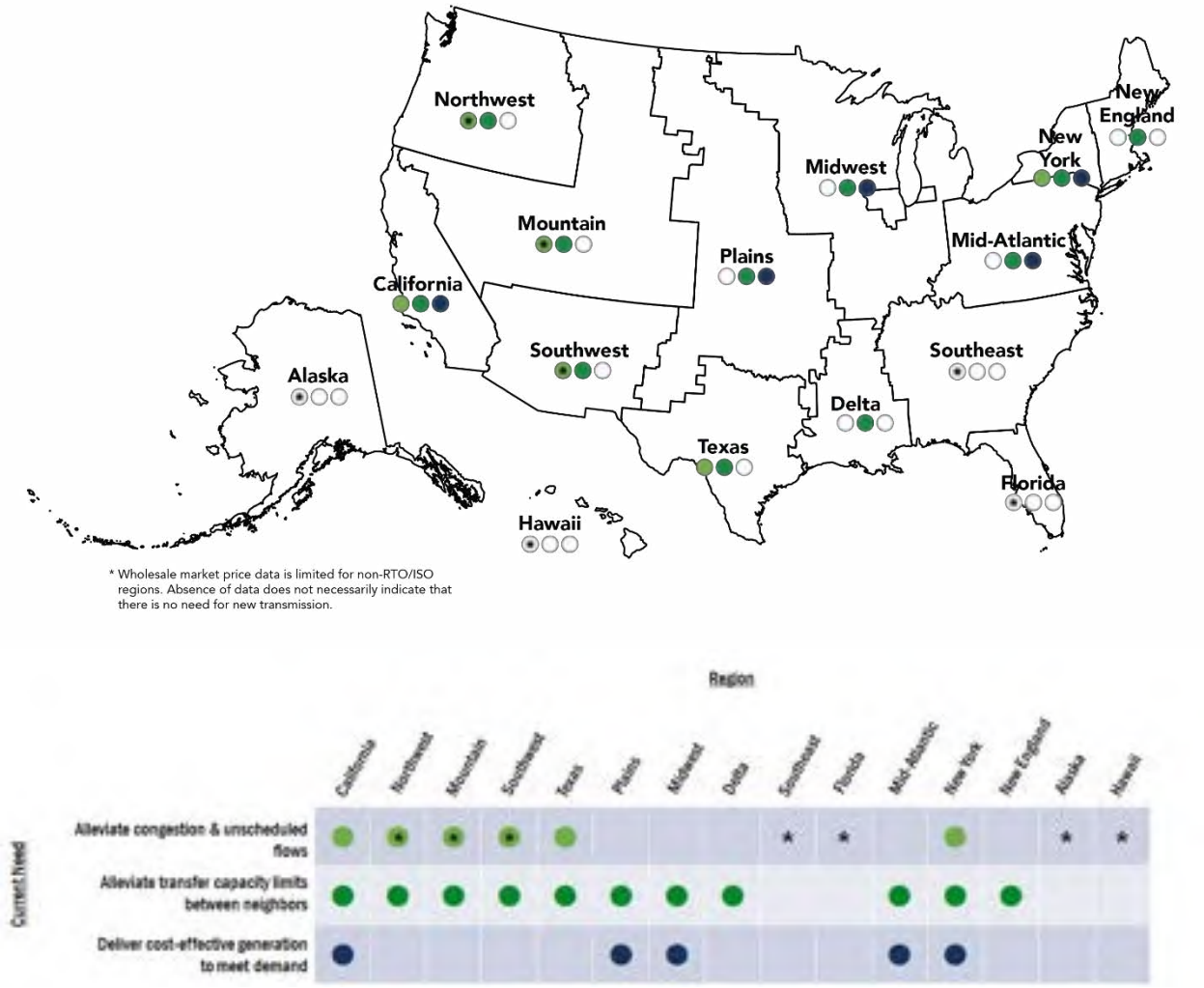



*Source: Data from Lawrence Berkeley National Laboratory; https://emp.lbl.gov/queues.*

***Figure IV-17. Indicators of the challenges facing transmission interconnection, planning, and construction. Right panel shows the median (black line) and interquartile range (green envelope) of years from generator interconnection request to operation for projects dating back to 2005.***

# IV.e. Conclusions

Figure IV-18 summarizes findings of current transmission needs by geographic region as determined by the data and studies referenced in the Section IV discussion of historical market conditions. The different color circles located on the map of Figure IV-18 (top) correspond to the transmission needs listed in the dashboard (bottom).




*Source: See Supplemental Material for supporting references and methodology.*

***Figure IV-18. Summary of current transmission needs identified in Section IV by geographic region.***

**A review of historical transmission system data from 2011 to 2020 provides information about the state of the grid today.** Regional differences in transmission capital expenditures ranged between $0.17 and $5.90 per MWh of regional annual load, on average over the last decade. These investments resulted in a national total of 33,000 circuit-miles of newly constructed or rebuilt transmission lines rated above 100 kV. Of these, 20,000 circuit-miles were higher capacity lines rated at least at 345 kV. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015.

**Wholesale market prices in the RTOs/ISOs provides insight into where transmission congestion currently exists.** Several regions of the country have had either consistently high or consistently low electricity prices over the past 3–5 years. Increased transmission access to persistently high-priced regions provides one way to lower prices for those consumers. Regions of high prices exist in Southwest MO, Southern OK, Northwest WI, Eastern and UP MI, Eastern MD/VA, Delmarva Peninsula MD and DE, Long Island NY, Southern Coast CA, and Northern Coast CA. These regional and interregional transmission links have significant potential economic value from reducing congestion and expanding opportunities for trade. Extreme conditions and high-value periods play an outsized role in this value of transmission, with 50% of transmission's congestion value coming from only 5% of hours.

**Examining differences in simultaneous market prices across the United States provides additional insight into the value of transmission during real-time operations.** The greatest transmission value is found by connecting regions in the middle of the country with their more eastern or western neighbors, particularly by connecting the three transmission interconnections. The highest value is found by connecting Texas to the Southwest region of the Western Interconnection, followed by connecting Texas with Plains and Delta regions in the Eastern Interconnection. There is also significant value in connecting the Plains with the Mountain region of the Western Interconnection and with Midwest and Delta regions to the east. The value of these interregional connections has been growing over the past 5 years of data considered. Identifying the best nodal locations to make these connections requires additional engineering analysis that considers downstream system upgrades to support increased energy transfers.

**In the non-RTO/ISO West, heavy traffic of energy moving from the Northwest into load centers in California and the Southwest causes congestion.** As of the publication of this report, the most congested paths are between Oregon and California and between Colorado and its three neighbors in the Western Interconnection, Wyoming, Utah, and New Mexico. This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced because of age, climatic changes (e.g., severe drought conditions), and advancing technologies. Additional transmission is one solution to addressing these concerns.

**A review of the power plants currently awaiting interconnection agreements in different parts of the country suggests the generation mix will continue to shift toward more wind, solar, and battery storage technologies.** The length of time from interconnection request to operation for all generation and storage resources has grown from less than 2 years in 2008 to more than 5 years in 2022. Generation resources with strong technical and economic potential located far from the existing transmission system—notably wind energy—require building new transmission to bring these low-cost resources to load (Brooks 2022). Storage technologies can help fortify the transmission system, helping ensure that the transmission built will be more highly utilized, as discussed in Section V.d.

# V. Current and Future Need Assessment and Identification of Transmission Benefits through Review of Existing Studies

This literature review surveys more than 120 recent reports to highlight the historical and anticipated drivers of transmission needs, the multiple benefits that additional transmission infrastructure can provide to consumers, and the challenges of expanding the Nation's electric transmission infrastructure. The literature includes reports from the U.S. Government, national laboratories, academia, consultants, and a cross section of industry participants that incorporate quantitative and qualitative measures of electricity transmission needs. Reports were chosen on the basis of geographic diversity, diversity among sources, and author subject matter expertise, and to cover a range of critical reliability and congestion issues faced by the transmission system today.[42] Similar to historic data analysis, regions that lack public reporting on the power system may be underrepresented here.

The reports considered as part of this literature review explore the historical and anticipated drivers of transmission, including reliability, resilience, curtailment, congestion, resource adequacy, interconnection of generation sources, and evolving demand trends. As discussed throughout the reports, upgraded and expanded transmission can provide an array of system resilience, reliability, and economic benefits in addition to facilitating access to clean sources of energy.

Additionally, various reports discuss opportunities to advance energy justice goals through the identification and mitigation of potential impacts to disadvantaged communities during transmission planning and development processes, as well as the importance of early and meaningful engagement with potentially impacted communities. Reports included in this literature review also consider the potential for deployment of alternative transmission solutions, such as GETs and other alternative transmission solutions, which reduce potential land use impacts while increasing energy access and supporting system reliability and resilience.

Recent literature identifies the challenges of meeting transmission needs, notably the fragmented approach to permitting and siting, complex planning, land use considerations, the need for improved quantification of benefits in cost allocation, and various other barriers.

## V.a. Reliability and Resilience

The recent literature reviewed for this Needs Study demonstrates that transmission infrastructure plays an important role in maintaining grid reliability, bolstering grid resilience, and addressing VER integration needs and emerging resource adequacy concerns.

FERC (2020) reports that high-voltage transmission can improve the reliability and resilience of the transmission system by enabling utilities to share generating resources, enhancing the

[42] A full list of studies, publishers, and funding sources can be found in the Supplemental Material.

stability of the existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services. Following disruptive events, high-voltage transmission lines can help with restoration and recovery by serving power from black start units once enough generation is operational. Additionally, high-voltage transmission lines help maintain a consistent frequency and enhance the stability of interconnected transmission by dampening interarea disturbances.

Addressing specific incremental grid reliability needs is a major driver of local transmission need, as cited in Brinkman et al. (2021), Clack et al. (2020b), and NERC (2021). As the power system continues to evolve, reliability is anticipated to remain a key driver of new transmission overall. NERC (2021), for example, finds reliability to be the dominant driver for planned transmission projects, noting that 64% of future circuit-miles of transmission are anticipated to be installed for reliability purposes. MISO (2022a) notes that the transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

A resilient transmission system can withstand many simultaneous maintenance-based or forced outages during even moderate electricity demand conditions. This resilience is especially important as scheduling outages becomes more difficult with an aging transmission system. The number of transmission facilities and associated components in need of maintenance often exceed a utility's ability to service them in a timely manner. This backlog of maintenance requests leads transmission owners to develop risk-based asset management techniques to prioritize the most critical assets (BPA 2022). While new transmission facilities can serve to improve system resilience, Pfeifenberger (2021) finds that recent efforts to replace aging transmission infrastructure create an opportunity to build a more robust, reliable grid, while efficiently using existing rights-of-way.

Further, transmission expansion can help to ensure grid reliability standards are met by increasing grid flexibility. Brinkman et al. (2021) and Brown and Botterud (2020) state that transmission—particularly interregional transmission—can increase grid operational flexibility. Ardani et al. (2021) similarly claim that transmission expansion is required to make the grid more flexible. Pfeifenberger (2021) claims that a more flexible and robust grid will reduce the risk of high-cost outcomes (both short and long term) that are due to inadequate transmission.

The ability of transmission expansion to support system reliability and resilience also extends to offshore systems. Pfeifenberger et al. (2020b) state that an offshore grid designed and built with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

Outside of the contiguous United States, Alaska and Hawaii's power systems have been found to need additional transmission capacity to support system reliability and resilience. Alaska's Railbelt region is composed of a roughly 700-mile transmission network stretching from Fairbanks through Anchorage and to the Kenai Peninsula, serving approximately 75% of the state's electric load. Within the Railbelt, a lack of system redundancy can create significant challenges during transmission outages. The Alaska Energy Authority (AEA) finds that the deployment of additional transmission paths parallel to constrained single lines, particularly

near the interties and certain areas of the southcentral Railbelt region, can help reduce the need for load shedding following contingency events (AEA and EPS 2017).

Transmission systems on Hawaiian Islands, such as Kaua'i, would also benefit from additional transmission capacity during contingency scenarios. Kaua'i Island Utility Cooperative (KIUC) describes that its system is capable of riding through a single contingency in accordance with its system voltage and frequency requirements with current generation and load levels (KIUC 2022). However, with anticipated load growth, additional transmission infrastructure would allow for a more resilient grid in the face of plausible contingency scenarios (KIUC 2022).

## Transmission can support a reliable grid with high penetrations of variable energy resource generation

VERs—such as wind and solar energy—are intermittent in nature and difficult to forecast at the temporal resolution (on the order of seconds) necessary for reliable operations. The rapid growth in the use of VERs poses unique grid reliability concerns that must be mitigated. Despite these reliability concerns, various study findings demonstrate transmission can serve to accommodate increased VER integration and increase system reliability in response to future changes in the generation mix.

NERC (2021) highlights that increased use of electrical inverters—which are required to connect batteries and many renewable energy resources to the grid—can lead to reliability concerns unless precautions are taken. System reliability concerns may arise from low inertia, unstable voltage, low fault currents, and unpredictable behavior of inverter-based resources during grid disturbances without appropriate precautions. In 2021, both Texas and California experienced the loss of widespread solar photovoltaic generation due to abnormal operation of inverters (NERC 2022a). Transmission planning, reliability studies, interconnection requirements, and operational control of the transmission system are crucial to account for the unique behavior of inverters on the grid (NERC 2021; NERC 2022a).

Novacheck et al. (2021) find that the operational and resource adequacy issues caused by historical high-impact weather events, such as the 2014 "polar vortex" that impacted the Midwest and the northeastern United States, have not been further exacerbated by a higher penetration of VERs on the electricity system. They do find, however, that milder versions of these weather events have resulted in concerns during prolonged periods of low VER availability. The authors note that expanding transmission to access geographically diverse energy resources—both firm and variable—can reduce these risks, suggesting that transmission can increase grid reliability in the face of risks posed by future weather events.

Similarly, ISO-NE finds in its *Future Grid Reliability Scenarios* study that even in a mild weather year—such as the 2019 weather year used in the study—weather events may pose significant challenges to maintaining electrical grid reliability in New England under a high VER future (ISO-NE 2022a). The study's reliability analyses show whether the simulation-produced generation mixes have either excess or insufficient capacity to serve load. ISO-NE finds that resource adequacy analysis overestimates the reliability of renewable resources during the hours of highest risk, suggesting more nuanced modeling of renewable resources is required to fully assess reliability under a scenario with high penetration of VERs. While ISO-NE finds fixed

output values used in the resource adequacy analysis for solar and wind are sufficient for the current New England system and resource mix, that assumption is no longer adequate in high VER penetration scenarios where widespread wind lulls and cloudy weather become more impactful (ISO-NE 2022a).

Clack et al. (2020b) model wind and solar resource development within the Eastern Interconnection and find that investing in transmission can help accommodate low-cost renewable energy integration without compromising system reliability. Clack et al. (2020b) determine that a strong transmission network can allow the bulk power system to be able to operate reliably in high VER penetration scenarios where wind and solar supply up to 82% of electricity by 2050.

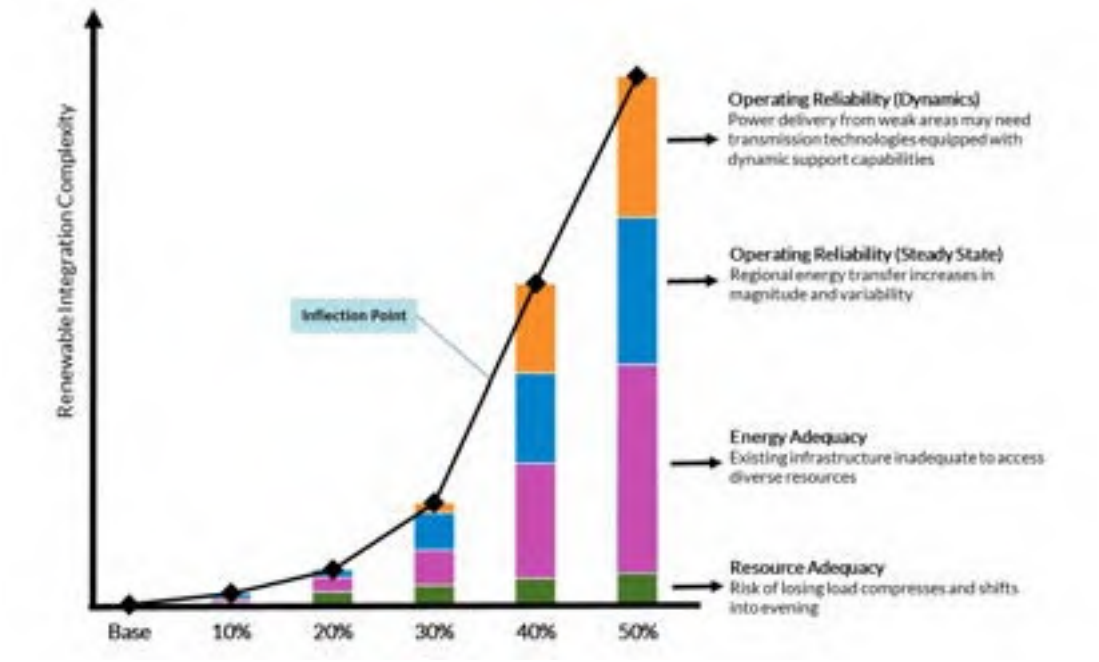
Prabhakar et al. (2021) describe MISO's *Renewable Integration Impact Assessment*, which examines the potential impacts and solutions for increased wind and solar installation within the Midwest and Delta regions. Prabhakar et al. (2021) conclude that the effort required to develop and operate new resources reliably as they are integrated with the grid substantially increases at renewable penetration levels beyond 30% of annual load served, as shown in Figure V-1.

MISO's LRTP initiative (MISO 2022a; MISO 2022b) also references its *Renewable Integration Impact Assessment* study and assesses reliability risks looking 10–20 years into the future to identify the transmission investments needed to enable regional delivery of energy. The LRTP process creates a portfolio of Midwest regional transmission solutions planned to address future energy needs and provide multiple benefits to consumers in the region, rather than using a project-by-project single benefit approach to reliability planning. LRTP projects are expected to deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the portfolio (MISO 2022a; MISO 2022b).

## Transmission can mitigate impacts of extreme weather events

Extreme weather events can impact all aspects of the power sector, including generation, transmission, and distribution. This section focuses on the role of transmission in maintaining system reliability and resilience during extreme events.

Novacheck et al. (2021) demonstrate how transmission can support system resilience during certain weather events. The authors explain that risks posed by regional icing and cold temperature shutdowns, although rare, can be mitigated by local gas generation dispatch and interregional transmission, either individually or in concert. Goggin (2021) similarly investigates the value additional transmission would have provided to the power grid during recent severe weather events. The study finds that an additional 1 GW transmission tie to the Southeast during the Texas heat wave of 2019 could have saved Texas consumers nearly $75 million.




*Source: Midcontinent Independent System Operator (MISO 2021).*

***Figure V-1. Additional operational effort (e.g., additional cost) is needed to maintain system reliability as renewable generation levels (x-axis) increase. The MISO transmission system maintains reliability up to 30% renewable energy generation without significant additional operational support.***

As discussed by NERC (2021), regions such as California, Texas, and the Northwest, where regional operators tend to rely on VERs and imports to meet demand during peak or high-risk periods, face higher risk of load curtailment during extreme conditions. NERC finds that regional grids in the Midwest, Delta, and Southwest regions are approaching similar conditions in the near term. NERC suggests adopting policies that promote the hardening of electric generation, transmission facilities, and fuel supplies to reduce risks to electricity reliability from extreme winter weather events (NERC 2021).

During the February 2021 winter storm event—often referred to as Winter Storm Uri—extreme cold temperatures and freezing precipitation across Texas and the southern Plains and Delta regions led to outages, derates, or failures at 1,045 individual generation units, resulting in a severe capacity shortage (FERC et al. 2021; NERC 2022a). For at least two consecutive days, ERCOT averaged approximately 34,000 MW of unavailable generation, including planned and unplanned outages. ERCOT estimates that peak generation outages and derates during the event totaled 52,000 MW, or 48% of total ERCOT installed generation capacity (ERCOT 2021c). At its peak, ERCOT shed 20,000 MW of firm load to make up for the generation shortfall (FERC et al. 2021; NERC 2022a). Goggin (2021) finds that each additional 1 GW of transmission ties between the Texas power grid and the Southeast region could have saved nearly $1 billion during the multiday winter storm, while keeping the heat on for hundreds of thousands of Texans. With stronger transmission ties, both the Plains and Delta regions also could have

avoided power outages while saving consumers in excess of $100 million with an additional 1 GW of transmission ties to power systems to the east (Goggin 2021).

FERC et al. (2021) note that limited interconnections between the Texas grid and its neighbors significantly affected its ability to make up for the capacity shortage experienced during the severe cold weather event of February 2021. MISO and SPP, the grid operator in the Plains region, also reached transmission limits on imports during the February 2021 severe cold weather event, although neither region was as severely affected as ERCOT (FERC et al. 2021). MISO and SPP were less impacted given the strength of their connections with adjacent neighbors that were unaffected by the storm. Improving transfer capability via increased ties with neighboring regions would increase ERCOT's ability to import power to address capacity shortages when its system is stressed under emergency conditions.

However, FERC et al. (2021) also comment that MISO and SPP would have been limited in their ability to increase exports to ERCOT during this event—had additional transfer capacity been available—without increased import capability with their adjacent neighbors in the Eastern Interconnection. The coincident scarcity of generation resources among ERCOT's immediate neighbors during this event calls into question the value of increased transfer capability limits without an accompanying increase in multiregional transfer capability, thereby making the power grid larger than the weather systems that impact it.

During the "bomb cyclone" cold snap across the northeastern regions in January 2018, the affected regions—New England, New York, and the Mid-Atlantic—could have saved $30–$40 million for each GW of stronger transmission ties among themselves or to other regions (Goggin 2021). These regions routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the 3-week event, demonstrating that transmission interconnecting multiple regions can benefit consumers across a broad geographic area. In addition, an additional GW of transmission capacity between eastern and western PJM, the grid operator for much of the Mid-Atlantic, would have provided over $40 million in net benefits during this event. Likewise, the "polar vortex" event in the Midwest in 2019 illustrates the benefits of transmission interconnecting multiple regions. As the extreme cold moved eastward from the Midwest to the Mid-Atlantic, operators were able to switch the direction of power flow to serve customers in need (Goggin 2021).

Increased connectivity between the Delta and Midwest could improve reliability and resilience in those regions, as evidenced by recent weather events. The Cold Weather Bulk Electric System Event in January 2018 resulted in transfers exceeding the Regional Directional Transfer Limit between the Midwest and Delta regions and resulted in transmission limitations that prevented the Midwest from reaching the Delta region (FERC and NERC 2019). FERC and NERC (2019) note that the Delta region nearly experienced load shedding during the cold weather event and required emergency energy purchases at one point during the event. The February 2021 winter storm event exacerbated these issues when generation loss in the Delta region and the declaration of a Maximum Generation Event caused multiple requests for a Regional Directional Transfer Limit increase to deliver more energy to the Delta region from the Midwest (MISO 2021). Most of these requests were denied as neighboring regions were experiencing similar constraints (MISO 2021). Similarly, Hurricanes Laura and Ida exposed further weaknesses in the

Delta region's connectivity, especially in certain transmission constrained areas, some of which experienced load shedding (Potomac Economics 2020).

Winter Storm Elliott's freezing temperatures disrupted reliability throughout large portions of the United States—including the Southeast and Mid-Atlantic—for several days in December 2022. The storm led to shutdowns or diminished output at certain generating units and triggered rolling blackouts for some customers in the Southeast region. Utilities relied heavily on imports from other regions during the storm, including imports of up to 5 GW from MISO (MISO 2023). Duke Energy reported a loss of approximately 1,000 MW of resources in the Southeast and blackouts occurred as customer demand exceeded projections (Duke Energy 2023). Tennessee Valley Authority (TVA) customers also experienced outages as several of TVA's generating facilities were unavailable throughout the Southeast region (TVA 2023). PJM reported forced outages of 24% of its total capacity in the Mid-Atlantic region, with losses primarily from natural gas and coal generation (PJM 2023b). However, PJM avoided outages in part because of its interregional transmission capacity (RMI 2023).

Goggin and Zimmerman (2023) assess the widespread impacts of 2022's Winter Storm Elliott on the Southeast region and analyze the hypothetical benefits that the region could have realized if it had additional connections with neighboring regions. They find that an additional GW of transmission between TVA in the Southeast and ERCOT in Texas would have generated consumer savings valued at an estimated $95 million during the 5-day storm. An additional one GW of transfer capacity between parts of MISO and TVA in the Southeast could have offered $75 million in value during the storm if connecting with Louisiana in the Delta region and $79 million if connecting with Illinois in the Midwest region (Goggin and Zimmerman 2023).

Winter Storm Elliott also highlighted the value of within-region transmission to support interregional transfer capability. During the storm, multiple transmission constraints within PJM's footprint in the Mid-Atlantic limited PJM's ability to support export transactions across its southern interfaces. In other words, because of the complex nature of transmission flows, interregional transfer capability can be limited by insufficient transmission capacity internal to a region (PJM 2023b).

The impacts of weather-related transmission outages can be widespread and severe. In MISO's *2020 State of the Market Report*, Potomac Economics (2021a) reports that transmission issues arose because of generation and transmission outages and the impact of Hurricane Laura in MISO South. Hurricane Laura damaged the Entergy transmission system and isolated load in southwestern Louisiana and the eastern parts of Texas that are in MISO South, forcing more than 6 GW of generation out of service. More than 500 MW of firm load was curtailed as a result (Potomac Economics 2021a). NERC (2022a) comments on the widespread outages in the Delta, Southeast, Texas, and Florida regions due to recent hurricanes, most notably Hurricane Ida in 2021. Over 1.2 million customers lost power and over 210 transmission lines were out of service due to Ida (NERC 2022a). Finally, transmission and other energy infrastructure is also vulnerable to the compound hazards of sea level rise and storm surge. As many as 40% more power plants and transmission substations along the Gulf Coast in Texas and the Delta could be exposed to increased risk for category 1 hurricanes under different sea level rise scenarios

(Bradbury 2015). The impacts of Hurricanes Laura and Ida emphasize the importance of improving resilience and hardening transmission infrastructure.

Maintaining system reliability in the face of severe weather is crucial for states like California, which balances severe weather as well as other extreme events, such as earthquakes and wildfires. California has become increasingly susceptible to extreme seismic risk (Field et al. 2017). Humboldt County in northern California, for example, is one of the most seismically active areas in the state because of the convergence of three tectonic plates (USGS 2022). In 2022, Humboldt County experienced a 6.4 magnitude earthquake, resulting in outages for roughly 70,000 customers (PG&E 2022). Increased seismic activity in an area that is already seeing increasing trends of sustained outages (PG&E 2021) could result in further grid-related issues.

High ambient temperatures in California are also increasing in both intensity and duration. A 2020 heat wave resulted in two rotating power outages, while another in 2022 increased average maximum daily temperatures by 5°F–15°F and forced demand on the grid to reach a new instantaneous gross peak record load of 52,000 MW (CAISO 2022a). Extreme heat in 2021 also impacted the Northwest grid, causing localized power outages (NERC 2022a). Transmission outages can also occur due to wildfires, particularly in California and the western United States, which can become exacerbated by extreme heat and drought. NERC (2022a) reports one major transmission system outage due to wildfires in 2021. As summer heat waves become more frequent and severe, the value of transmission for delivering needed electricity supplies from regions that are currently less affected will grow.

Transmission planning entities are increasingly accounting for risk from extreme weather events in their longer-term transmission plans. WECC is considering incorporating weather and climate data into load forecasts to help inform system planners in the California, Northwest, Mountain, and Southwest regions on whether transmission investments will serve both the changing demands of the system and be resilient against extreme events (WECC 2023). SPP recommends expanding its transmission planning scenarios to consider more extreme transmission contingencies and additional extreme weather to account for increasing frequency and volatility of weather patterns in the Plains region (SPP 2023). SPP notes that more extreme weather patterns will lead to more extreme load patterns, making load more difficult to forecast.

NERC (2022a) notes that the ability of the power grid to withstand and recover from extreme events is increasingly important as the intensity and frequency of severe weather grows due to climate change. Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones.

## Increased grid connectivity can support resource adequacy

Resource adequacy is the ability of supply- and demand-side resources to meet the aggregate electrical demand of a region (NERC 2022b), including under extreme conditions when critical generators may become unavailable. Regions meet their resource adequacy requirements through a mix of regional generation, demand response, and firm capacity transfers across intra- and interregional transmission lines.

Patton et al. (2021) assert that new transmission capacity can provide substantial resource adequacy benefits, as new lines enable more flexible generation sharing, reducing the need for new generation. Brinkman et al. (2021) note that transmission is needed in the near term for resource adequacy, and more importantly in the long term due to the anticipated increase in clean energy resource integration. Brinkman et al. (2021) also conclude that transmission expansion can provide economic benefits and improve grid reliability by maintaining resource adequacy. MISO (2022a) similarly reports that its LRTP portfolio will expand system transfer capacity, allowing for utilities to use new or existing resources from elsewhere in the Midwest region rather than constructing new, local generation to meet resource adequacy obligations.

Ardani et al. (2021) and Bloom et al. (2020) similarly explain that expanding transmission can help ensure resource adequacy needs by allowing regions to access a diverse set of resources from outside of their respective footprints. CAISO's *20-Year Transmission Outlook* identifies a combination of new and existing transmission resources that could deliver 12,000 MW of out-of-state wind to the CAISO system by 2040, improving resource diversity (CAISO 2022b). SPP's Future Grid Strategy Advisory Group notes that establishing and improving resource adequacy coordination processes can also lower infrastructure development costs in the Plains region, while improving grid resilience (SPP 2023). Additionally, connecting geographically diverse resources can help reduce electricity costs by reducing the need for excess generating capacity, particularly for regions that have non-coincident demand peaks. Ardani et al. (2021) explain that DERs can offset the need for some transmission resources in ensuring resource adequacy by shifting diurnal peak demand. Xu et al. (2021) assert that given current assumptions about the future, substantial transmission investments will be necessary to ensure reliable renewable generation deliverability and system adequacy.

Novacheck et al. (2021) emphasize that even during extreme events of low wind and solar output, VERs can contribute to resource adequacy via interregional coordination and bidirectional trading of power through the transmission system. Although the historical high-impact weather events considered by Novacheck et al. (2021) did not lead to new operational or resource adequacy concerns for an electricity system with high VER penetration, the report notes that milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability. For example, wind generation tends to decrease during periods of prolonged cold weather after a cold front moves through an area. These periods can pose challenges to resource adequacy as solar output is typically already lower during the winter months. Similarly, moderate heat waves accompanied by persistent high pressure can depress wind generation during evening net load peak. Expanding transmission to integrate geographically diverse VERs can reduce these risks, lower capacity reserve margins, and reduce system costs. Resource adequacy studies do not fully consider these milder weather events, however, and therefore current planning to ensure enough generation and transmission infrastructure exist to meet load is likely insufficient.

ISO-NE's *Future Grid Reliability Scenarios* study (ISO-NE 2022a) uses a resource adequacy reliability analysis to explore what conditions will likely present operational or reliability issues under future New England grid scenarios. ISO-NE finds that scenarios without dispatchable units require a significantly larger buildout of renewable generation. The *Future Grid Reliability Scenarios* study also finds that resource diversity is critical. In cases for which only a single

generation type is added, future scenarios either do not meet reliability criteria or require what may be infeasible quantities of those resources. Generation diversity—including combinations of onshore and offshore wind, solar, battery storage, and hypothetical dispatchable emission-free resources—reduces the need for new generation and storage resources by up to 17,000 MW per the study. This analysis finds that resource adequacy criteria can be met by a variety of diverse resource mixes, but that dispatchable resources are particularly effective at providing resource adequacy.

Prabhakar et al. (2021) conduct modeling to assess the reliability of the electric system with increasing levels of wind and solar in the Midwest and Delta regions. The report finds that no transmission solutions are needed for resource adequacy purposes at up to 30% wind and solar penetration due to over-builds in renewable capacity. However, beyond 40% wind and solar penetration, the report finds that new transmission is necessary.

RTOs/ISOs identify a need for transmission upgrades and new construction in their long-term plans, driven by dispatchable generator retirements and rapid increases in renewable capacity (ERCOT 2022b; ERCOT 2022c; MISO 2022a). Similarly, utilities in the Midwest also identify the need for additional transmission infrastructure to support system reliability as the generation fleet transitions to incorporate more non-dispatchable resource capacity and retires an increasing number of dispatchable generators (CapX2020 2020). The utilities note that additional transmission between regions will support increased grid flexibility and system stability by allowing for capacity imports and exports between regions to ensure that energy needs are met for all hours of the year.

PJM (2023a) studies the impacts associated with the energy transition in the Mid-Atlantic region with a focus on resource adequacy in the near term through 2030. The study findings highlight that reliability risks may arise in the near term, largely driven by electricity demand growth due to high-demand data center development in the region, economic and policy-driven thermal generator retirement that outpaces new resource development, and the increase in intermittent and limited-duration resource interconnection requests. PJM notes that it may need to order transmission upgrades or additions built by transmission owners in the region to maintain resource adequacy and accommodate generation loss in the face of these anticipated reliability risks.

NERC (2021) finds that generation retirements over the next few years in the Midwest and Delta regions will result in capacity shortfalls as early as 2024 without additional generation or import transfer capacity additions. By 2026, MISO's reserve margin capacity shortfalls will be an estimated 3 GW (NERC 2021). NERC stresses that resource adequacy and energy sufficiency measures need to be urgently implemented in the area. MISO planners similarly predicted capacity shortfalls in previous iterations of the Organization of MISO States' MISO survey (NERC 2021). While the shortfalls ultimately have not yet occurred, the continued identification of capacity shortfalls as a concern for the Midwest and Delta regions emphasizes the persistent need for resource adequacy measures, such as new transmission to access additional resources and improve overall resource diversity.

Regions in the Western Interconnection face even more immediate concerns as current resources are insufficient to meet demand during widespread heat events, particularly without

resource diversity to complement the loss of solar generation in the late afternoon. In 2021 NERC estimated the Northwest could see 23 load-loss hours in 2022 and the Southwest has the potential for load-loss hours starting in 2024 (NERC 2021). NERC further estimated that California could face up to 10 hours of load loss beginning in 2022 and 75,000 MWh of unserved energy as soon as 2024 given the extreme heat events considered in its analysis. By 2026, California will experience an estimated 3 GW of capacity shorfalls (NERC 2021). Additional interregional transfer capacity is one means to make up for these reserve margin shortfalls, so long as neighboring regions have excess generation to export at the time of need.

FERC et al. (2021) recommend that adjacent reliability coordinators, BAs, and transmission operators perform bidirectional power transfer studies to determine constraints that could occur when importing or exporting power between neighboring regions during an emergency that spans multiple reliability coordinator/BA areas. NERC (2021) makes a similar recommendation, recognizing that resource planners in the Western Interconnection are increasingly reliant on external transfers to meet capacity reserve margins. This dependence on import capacity will require coordinated resource adequacy and transmission planning to ensure reliability.

In the Southeast, Georgia Power Company's *2022 Integrated Resource Plan* proposes a Reliability & Resilience Action Plan to address future reliability needs associated with the potential for future fossil generator retirement in northern Georgia (Georgia Power 2022). Specifically, the plan notes that northern Georgia relies on transmission to transfer power from areas to the south, and in the event of generator retirement, existing transmission infrastructure is not sufficient to support reliable electric service to the north.

In Alaska, Financial Engineering Company (2022) analysis finds that planned and anticipated thermal resource retirements in the northern Railbelt region will require capacity replacement from new renewable resource installations and power purchase agreements with southcentral gas generators to ensure resource sufficiency. The increase in capacity from gas power purchase agreements requires an upgrade of the Alaska Intertie to allow increased capacity delivery to the north.

## Interregional transmission across the interconnection seams can improve reliability and resilience

Like resource adequacy, greater interregional transmission connectivity can provide increased reliability and resilience value. This value is particularly highlighted when connecting across the three interconnection seams.

As discussed in Section IV.b, Millstein et al. (2022a) calculate hourly transmission congestion values between different links in the contiguous United States from 2012 to 2021. They find that very few hours (5%) account for a large portion of transmission value and that a small number of extreme events (1–3 over 10 years) contribute meaningfully to the total 10-year value of a particular link. The transmission value that Millstein et al. (2022a) calculate could therefore be considered "insurance" against the high costs faced during extreme grid conditions, weather events, or other factors, such as unexpected deviations from forecasted conditions. Each stakeholder's potential benefits from this insurance value of transmission

depends on the characteristics of future extreme grid conditions or weather events that are unpredictable. The attribution of this complex value is another challenge transmission planners face as they strive to weigh the costs and benefits of transmission expansion projects. Transmission planners run the risk of understating the benefits of regional and interregional transmission if extreme conditions and high-value periods are not adequately considered (Millstein et al. 2022a).

As noted above, the February 2021 winter storm event had reliability implications across the Texas, Plains, and Delta regions. As FERC et al. (2021) observe, unlike other regional markets like MISO and SPP that were also affected by the severe cold weather event, ERCOT has very limited interconnections with its neighbors. ERCOT can only import just over 1,000 MW across its ties to its neighbors, which significantly affects its ability to make up for the region's capacity shortage. FERC et al. (2021) make recommendations to mitigate future outages of this magnitude within the Texas system,[43] one of which is that ERCOT conduct a study to evaluate the benefits of additional ties with the Eastern Interconnection, the Western Interconnection, or Mexico. The benefits could include increased import capability to help address capacity shortages during emergencies. Improving import capability would therefore help improve the overall reliability of the Texas system.

Bloom et al. (2020) identify transmission expansion across the interconnections as a way to reduce generation capacity required for reliable grid operations, as diversifying load and generation across large geographic areas can increase operating flexibility. Xu et al. (2021) further conclude that high-voltage direct current (HVDC) connections that span across interconnection seams enable renewable resource generation to be shared more readily between interconnections. The authors argue that given existing assumptions about the future, sizable transmission additions are necessary to ensure system reliability. Clack et al. (2020b) comes to similar conclusions, arguing that continental-scale transmission—expanding from the Western Interconnection to the Eastern Interconnection to ERCOT and Canada—can improve reliability by capturing even greater geographic diversity of generation resources.

The interconnection seams could be further connected via back-to-back DC connections—as is the case now—or using AC transmission. Overbye et al. (2021) evaluate the potential to synchronize the Eastern and Western Interconnections using a combination of high-voltage alternating current and AC-DC-AC converter stations spanning the entire seam between the two interconnections. The study assesses stability issues that could arise with synchronization and finds that generator governor action could result in asymmetrical responses under contingency conditions. In the event of a generator loss contingency in the Western Interconnection, approximately 80% of the lost power will flow from east to west because the Eastern Interconnection has almost four times the load of the Western Interconnection. The authors conclude that the interface joining two such grids would need reinforcing to handle the possible increase in flow that would occur under contingency conditions.

[43] FERC et al. (2021) make 28 recommendations in all, many of which relate to preparing generation units to operate in cold temperatures and using more reliable weather, resource, and load forecasts.

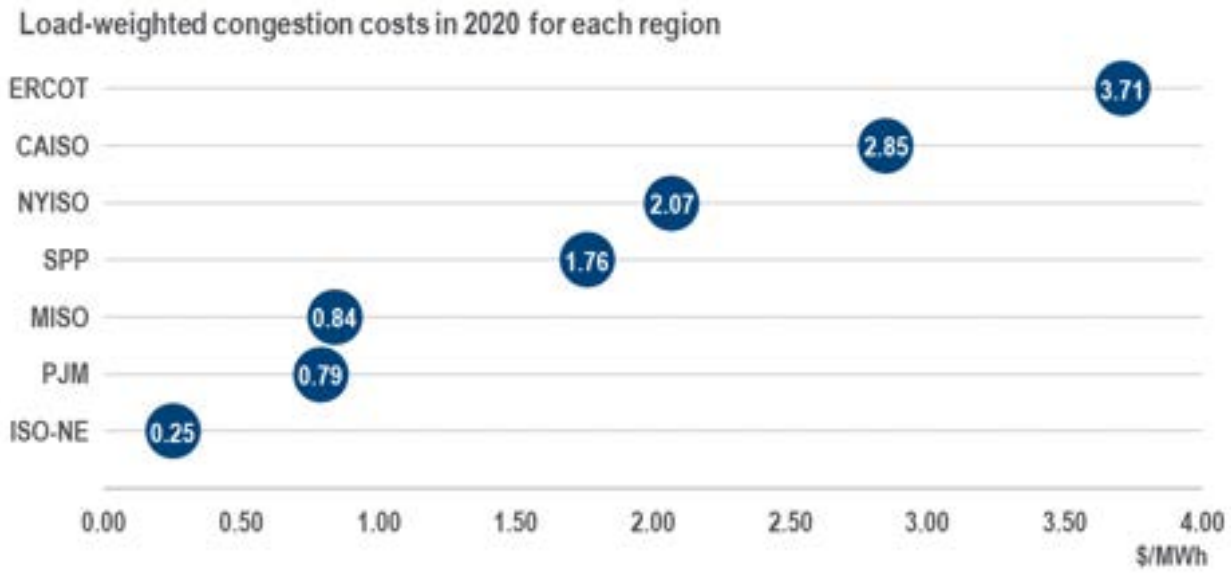
# V.b. Regional Congestion and Constraints

Congestion is another major indicator of transmission need; various reports reviewed discuss congestion and constraints as a driver of transmission infrastructure needs in several regions, including Ardani et al. (2021), Pfeifenberger (2021), FERC (2020), and NERC (2021). Transmission congestion between lowest-cost generation sources and load may require higher cost generation sources that are not impacted by congestion to serve load, raising wholesale electricity prices for those customers. FERC (2020) indicates that transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion. In unconstrained cases, where the transmission system is modeled as a single-bus system in which transmission has unlimited capacity, no wholesale market price separation exists (ISO-NE 2021). New deployment of transmission, along with storage and other alternative transmission solutions (discussed further in Section V.d.), can alleviate congestion. If a transmission facility is being considered for the sole purposes of alleviating congestion, the cost of the project would need to be less than the congestion costs that are alleviated for the project to be financially viable.

MISO (2022a) relies on congestion and fuel cost savings as another one of many quantified benefits gained from the transmission projects proposed in their LRTP Tranche 1 Portfolio. The congestion value of transmission calculated by Millstein et al. (2022a), discussed in Section IV.b, is derived from the value of allowing a lower cost set of generators to meet load and by increasing operational flexibility through reduced congestion and increased interregional trade. Thus, value can also be thought of as the potential to reduce system cost through reducing congestion. In other words, properly accounting for the full suite of values that derive from transmission is critical toward building a least-cost electricity system.

This section discusses transmission congestion found in each region, primarily using utility industry and market monitor reports in each area. RTO/ISO market monitor reports identify the costs incurred in each market (and ultimately borne by consumers in most cases) due to transmission congestion and constraints. Less granular data on how transmission congestion and constraints raise overall system costs for consumers is available in non-RTO/ISO regions.

Figure V-2 shows a summary of 2020 load-weighted congestion costs in each RTO/ISO market from the reviewed market monitor reports. Load-weighted congestion costs are highest in Texas and California.




*Source: ISO New England (ISO-NE 2021b, p. 120), Potomac Economics (Patton et al. 2021b, p. 26), Southwest Power Pool, Inc. (Warren et al., 2021 p. 198), Monitoring Analytics, LLC. (Monitoring Analytics, LLC. 2021, p. 69), Potomac Economics (Potomac Economics 2021a, p. 59), California Independent System Operator (Hildebrandt et al. 2021, p. 195 for DA and p. 111 for RT congestion), and Potomac Economics (Potomac Economics 2021b, p. 47). Midcontinent Independent System Operator (MISO) system load calculated from MISO 2020 Regional Actual Load, which can be found at (MISO 2020). Electric Reliability Council of Texas (ERCOT) system load taken from 2020 Demand and Energy Report (ERCOT 2021a).*

*Note: Factors considered in calculating the congestion cost may vary from region to region; therefore, these load-weighted congestion costs represent best estimates and are presented for comparison purposes.*

***Figure V-2. 2020 load-weighted net congestion cost by region.***

## While historic transmission investments in New England have resulted in low congestion, future generation changes are expected to increase congestion in some areas

Patton et al. (2021a), in their 2020 assessment of the ISO-NE electricity markets, finds that ISO-NE has lower congestion costs compared with other RTOs/ISOs because of significant transmission investments over the past decade. These investments, however, have led the region to experience higher transmission service costs per MWh of load compared to ERCOT, MISO, PJM, and NYISO. ISO-NE experiences about 10%–20% of the congestion levels in other RTOs/ISOs as a result of these large transmission investments (Patton et al. 2021a). New transmission likely will not be needed in the near term to alleviate congestion internal to the ISO-NE system. NERC (2021) also states that transmission expansion in New England has improved reliability and resilience, reduced air emissions, and lowered wholesale electricity market costs by nearly eliminating congestion.

Patton et al. (2021a), however, describe the effect of transmission limitations on import capability in certain parts of the ISO-NE region. The assessment states that the combined lower Southeastern Massachusetts (SEMA) and eastern Rhode Island area is import constrained, and further transmission maintenance outages can reduce import capability from New Hampshire to Maine and increase reliability commitments in Maine.

Additionally, ISO-NE (2020) notes that transmission enables low-cost resources to produce more energy, lowering wholesale electricity prices for several subareas. However, the study also finds that an increase in low-cost offshore wind interconnection in the SEMA/Rhode Island subarea intended to serve load outside of the subarea is expected to increase congestion at the SEMA/Rhode Island export interface due to an oversupply of wind generation. Additional transmission to connect load centers in Connecticut and Massachusetts to this available offshore wind generation can alleviate this challenge. Further transmission expansion could be needed to avoid transmission-related wind curtailment, some of which can be avoided by developing resources near load centers. ISO-NE (2021) states that building extensive low production cost generation in one area, rather than near load centers, increases congestion, creating a need for new transmission.

The New England region is planning for interconnections of large amounts of offshore wind energy in the next several years. Selecting appropriate points of interconnection for offshore wind requires tradeoffs between costs, interconnection size, and risk of overloads. To address these tradeoffs, ISO-NE suggests a standard offshore wind farm size of 1,200 MW for points of interconnection in the Boston area, which would reduce the potential for overloads and limit the required number of HVDC converter stations (ISO-NE 2022b). Larger interconnections would be possible outside of the Boston metropolitan area, according to ISO-NE.

## Largest transfer limitations within New York are between upstate and Long Island

In NYISO's *2020 State of the Market Report*, Patton et al. (2021) report that the COVID-19 pandemic reduced demand and had a larger effect on commercial customers than other customers. Thus, the decline in load was more pronounced downstate, which reduced congestion from upstate to downstate. Energy prices ranged from an average of $13.28/MWh in the North Zone to $28.03/MWh in Long Island due to transmission congestion and losses. However, congestion overall declined relative to 2019 because of lower load levels from the pandemic and lower natural gas prices. Day-ahead congestion revenues fell 31%, from $433 million in 2019 to $297 million in 2020, the lowest level since NYISO began operation. Still, the Central-East interface, which usually accounts for the largest congestion, continued that trend in 2020, with 39% of total day-ahead congestion value. Top congested corridors included the West Zone (19%), Long Island (17%), and New York City (8%). Average 2020 real-time energy prices and congestion in NYISO are shown in Figure V-3.

Transmission outages and other factors that limit transmission capability resulted in day-ahead congestion shortfalls. The most significant was the lengthy outage of a high-capacity 345 kV circuit. Outages on two submarine HVDC lines into Long Island also caused significant congestion. Further, transmission outages related to the construction of the Moses-Adirondack Smart Path Reliability Project, a project meant to help New York reach its public policy goals, resulted in reduced transfer capability out of the North Zone.

NYISO also improved the efficiency of scheduling and pricing in some areas by reducing the use of out-of-merit actions to manage constraints on low-voltage lines. In 2018, NYISO started incorporating some 115 kV constraints in the market software, reducing out-of-merit

generation actions used to manage these constraints from 260 days in the West Zone in 2018 to 13 days in 2020 and from 130 days to 8 days in the Capital Zone over the same timeframe.

The 20-year outlook of New York's system resources and transmission constraints also anticipates further congestion issues. To meet the state's Climate Leadership and Community Protection Act's goals by 2030 and 2040, additional renewable generation is needed. NYISO has identified that the local and bulk transmission systems are inadequate to achieve these goals, limiting effective delivery of renewable energy to consumers. Long-term planning scenarios with a significant portion of renewable generation would exacerbate existing transmission congestion with a 23% increase statewide by 2030 (NYISO 2022a).

*Source: State of the Market Report for NYISO 2020 (Patton 2021b).*

***Figure V-3. Real-time energy and congestion prices ($/MWh) in NYISO in 2020.***

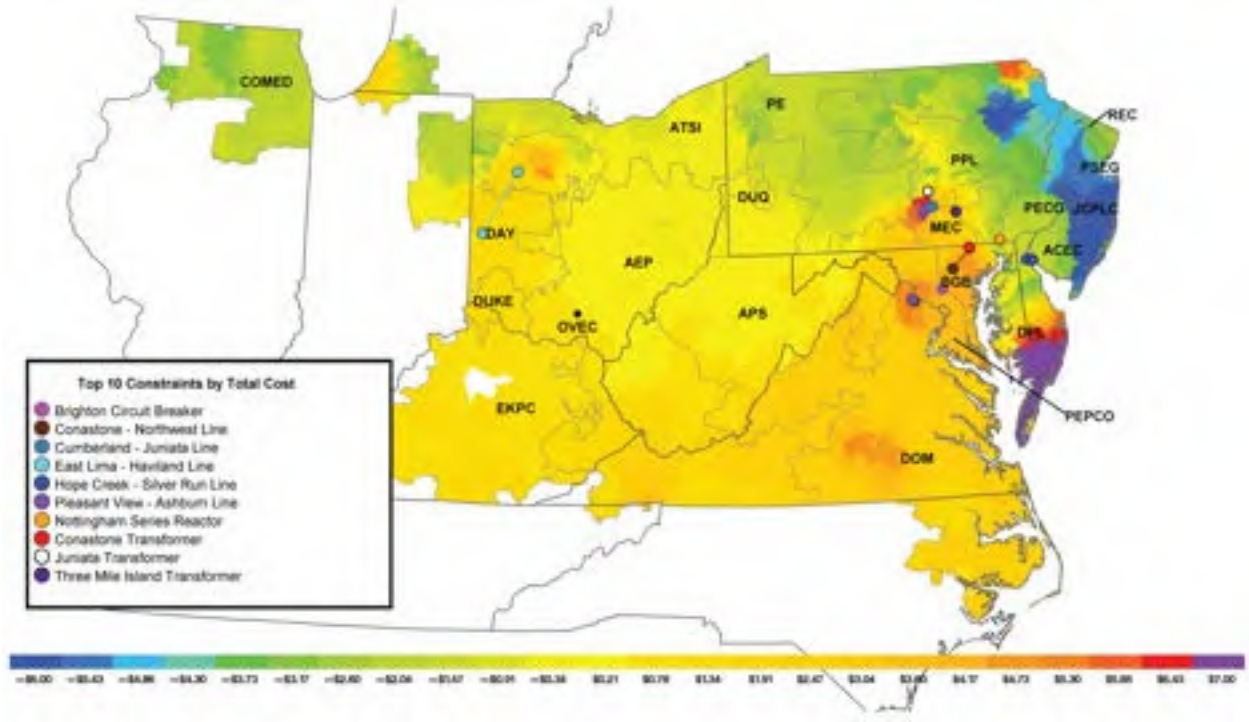
## Significant congestion and constraints exist in the eastern, coastal Mid-Atlantic

In PJM's 2021 *State of the Market Report*, Monitoring Analytics (2022) records that total congestion costs increased in 2021, from $528.7 million in 2020 to $995.3 million in 2021, an approximately 88.2% increase. The top 10 facility constraints with regionwide impact are shown in Figure V-4, along with average 2021 congestion costs in the PJM region. A portion of the congestion associated with these constraints is a result of scheduled transmission outages to accommodate system upgrades.

Monitoring Analytics (2022) also provides information on transmission constraint shadow prices, which represent the marginal change in total production cost from relieving a constraint by 1 MW and can signal congestion on certain lines. The average shadow price of PJM's internal transmission constraints almost doubled, from $92.23 in 2020 to $183.04 in 2021. For the first time since 2007, the cost of the transmission price component was more than the capacity

price component for the wholesale energy price (on a per MWh basis), which shows a need for transmission upgrades within PJM to reduce congestion.

Monitoring Analytics (2022) also describes the impact of TLR in PJM and neighboring regions. According to the report, the impact of TLR procedures issued by PJM decreased in 2021, compared with 2020. PJM issued two Level 3a or higher TLR procedures each in 2020 and 2021, but no related curtailments occurred in 2021, compared with 1,789 MWh of curtailments in 2020. Monitoring Analytics (2022) indicates, however, that during the same period, curtailments related to MISO and NYISO transmission load relief increased. The number of curtailments MISO issued decreased from 93 in 2020 to 75 in 2021, but curtailments increased from 58,520 MWh to 70,231 MWh, respectively. Monitoring Analytics (2022) adds that NYISO issued three Level 3a or higher TLR procedures in 2021 compared with two in 2020. Related curtailments increased sharply, from 1,030 MWh in 2020 to 27,754 MWh in 2021. As described in Section III.d., TLR only partially describes the congestion in RTOs/ISOs in which real-time transmission congestion is predominantly managed in the wholesale electricity markets. Nevertheless, the large increase in curtailments of generation show a need for transmission to alleviate constraints and allow energy from these resources to flow to consumers.




*Source: Monitoring Analytics (Monitoring Analytics 2022).*

***Figure V-4. Location of the top 10 constraints by total congestion costs: 2021 ($/MWh).***

## Significant constraints and congestion exist between the Midwest and Delta

In MISO's *2020 State of the Market Report*, Potomac Economics (2021a) records that congestion costs in MISO increased because of increased wind output, generation and transmission outages, and the impact of Hurricane Laura in the Delta region of MISO, highlighting the importance of transmission to increased system resilience. Potomac Economics

(2021a) reports that MISO's Regional Directional Transfer Limit was frequently binding from south to north because of higher-than-normal temperatures in the Midwest region of MISO, meaning that available generation in the Delta region of MISO could not be dispatched to serve Midwest customers with high cooling load needs. Flows were correlated with wind in other months. All wind resources within MISO are currently located in the Midwest region, and as a result, generation from wind resources flows north to south when wind generation is high and in the reverse direction when wind generation is low. The ability to shift the quantity and direction of flows provides significant value to customers as the lowest-cost available generation switches between the Midwest and Delta regions. Congestion between the two regions prevents low-cost generation from reaching customers on the other side of the transfer limit. Similarly, these findings highlight the need for increased access to a more diverse generation portfolio, which can be achieved through additional interregional transmission.

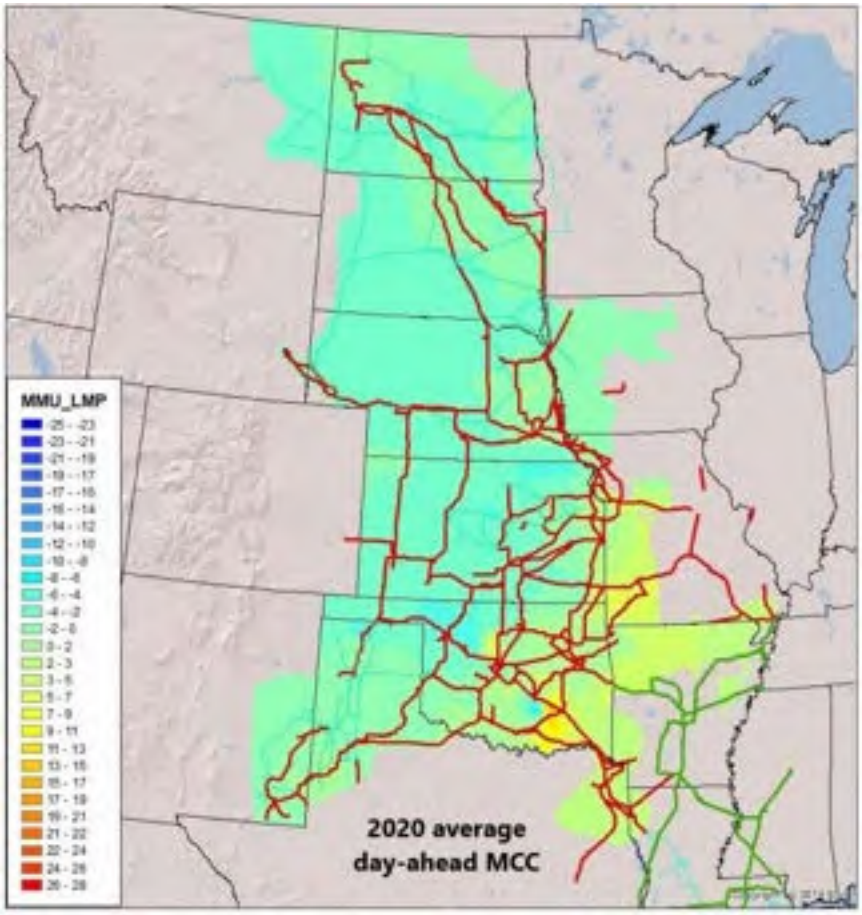
Despite lower gas prices and transmission upgrades in MISO, the value of real-time congestion rose by 26% to $1.2 billion in 2020 relative to 2019. Although congestion in the South and Central regions fell, congestion in the North region more than doubled because of increased wind output. The use of conservative static ratings and limitations of MISO's authority to coordinate outages contributed to higher than optimal real-time congestion. MISO has no authority to deny or postpone planned outages, even if such action would result in significant economic benefits. The Independent Market Monitor recommends that MISO files for increased authority to coordinate planned transmission and generation outages to reduce unnecessary economic costs.

According to Potomac Economics (2021a), congestion also affects MISO's interchange with neighboring markets. MISO's market-to-market (M2M) process serves to efficiently and cost effectively manage constraints affected by MISO and its neighboring RTOs by providing a mechanism for the RTO with the more economic redispatch to relieve congestion. The M2M process compensates the RTO with the lower cost of managing the constraint the marginal value of constraint relief. Congestion on MISO's M2M constraints increased 37% in 2020 to $530 million (45% of all congestion in MISO) relative to 2019. MISO uses M2M processes to manage congestion on MISO constraints that are also affected by generation in PJM in the Mid-Atlantic and SPP in the Plains (and vice versa). High wind generation along the seams with SPP and generator retirements contributed to a 400% increase in M2M payments ($80 million net payment) from MISO to SPP. MISO's external market monitor recommends measures to improve the M2M coordination and reduce M2M congestion costs.

In addition, Potomac Economics (2021a) describes the negative impact on the MISO market of TLR with MISO's neighbors. For example, TLR procedures called by the Independent Electricity System Operator of Ontario (IESO) in Canada resulted in curtailments of large amounts of power from PJM to MISO, creating price spikes in MISO. Potomac Economics (2021a) also finds that TVA generation in the Southeast could have relieved $63 million in congestion costs in MISO caused by TLR constraints. MISO's external market monitor recommends that MISO coordinate with TVA and IESO to develop mitigation measures.

## Congestion in the Plains is related to limited transmission capacity and high wind generation output

In SPP's *2020 State of the Market Report*, SPP's external market monitor (Warren et al. 2021) records that congestion due to high wind generation output and transmission limitations affected 2020 pricing in some locations. The southeastern corner of SPP, including eastern Kansas, southwestern Missouri, and southeastern Oklahoma experienced the highest congestion costs. Figure V-5 shows a map of average 2020 day-ahead congestion costs, as reflected in the marginal congestion component of the locational marginal price. Net congestion costs totaled over $442 million because of high wind generation and transmission limitations. Congestion costs in 2020 were 8% lower than those in 2019. Price differences between the SPP North and SPP South hubs remained relatively small in 2020 ($0.23/MWh average day-ahead price difference) because of reduced congestion resulting from transmission expansion and a milder summer in the southern region. Transmission upgrades within SPP, including upgrades in the upper-central region of Oklahoma and central Kansas, have increased transmission capability for wind-producing regions and reduced prices in previously congested regions.




*Source: Southwest Power Pool State of the Market 2020 (Warren et al. 2021).*

*Note: Transmission lines shown in cyan (<345 kV), red (345 kV), or green (>345 kV).*

***Figure V-5. Average day-ahead marginal congestion cost ($/MWh) in SPP in 2020.***

In addition, SPP experienced an increase in M2M payments from MISO. Total payments from MISO were $82.8 million in 2020, compared with $17.5 million in 2019. This increase in total M2M payments demonstrates congestion at flowgates along the MISO-SPP seam has increased since 2019, particularly at flowgates in eastern Nebraska, southwestern Missouri, southeast and Northeast Kansas, as well as eastern Oklahoma, and northern and western Missouri. SPP's external market monitor recommends evaluating the processes and mechanisms between SPP and MISO through a joint study addressing the inefficiencies between the two markets. As MISO's wind penetration continues to increase, SPP's M2M flowgates will continue to be affected and potentially lead to an increase in the M2M payments from MISO. The M2M coordination study estimates a reduction of $35 million in annual congestion costs by automating processes that promptly identify and activate constraints in SPP and MISO's M2M systems.

In MISO and SPP's Joint Transmission Interconnection Queue (JTIQ) Study (MISO and SPP 2022), the system operators recommend a five-project transmission portfolio that relieves constraints in both markets, enables the interconnection of large amounts of renewable generation near the Midwest-Plains seam, and provides other significant benefits. The portfolio relieves 48 reliability constraints across both markets. The JTIQ Portfolio resolves constraints that allow MISO to interconnect over 28 GW of additional generation near the seam, while SPP estimates it would be able to interconnect over 53 GW of additional generation. The JTIQ study suggests that building additional transmission connections between SPP and MISO will reduce grid constraints and congestion costs borne by consumers and improve performance.

## Constraints and congestion costs in the West are growing as the generation resource mix changes and demand grows

Hildebrandt et al. (2021) describe the impact of congestion in CAISO. Transmission constraints and greenhouse gas compliance costs result in higher prices in CAISO than in the areas of the Northwest, Mountain, and Southwest that participate in the WEIM. CAISO's *2020 Annual Report on Market Issues and Performance* identifies congestion in both the day-ahead and 15-minute markets in 2020. Locational price differences because of congestion in both the day-ahead and 15-minute markets increased in 2020, particularly as a result of constraints associated with major transmission congestion on lines between Northern and Southern California and on those connecting CAISO and the Northwest.

Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) increased by 74% from $152 million in 2019 to $263 million in 2020. This increase was primarily due to increased congestion on the two major interties linking CAISO with the Pacific Northwest, where total congestion charges tripled to $236 million in 2020 relative to 2019 as a result of increased import congestion frequency on the interties during the third quarter. In California overall, congestion resulted in higher prices in Southern California load zones, and lower prices in the Northern California load zone.

Emerging trends in load and generation changes will have a large impact on future interregional transmission capacity utilization in the Western Interconnection. The WECC *2028 Scenario Reliability Assessment* (Bailey and Mignella 2020) examines utilization along transmission paths

in a 2038 reference case and four additional scenarios. The most highly utilized paths may need to be expanded if existing transfer capacity cannot meet future generation and demand needs. Many paths are expected to be highly utilized in the near- to mid-term, but the level of utilization of these paths is expected to increase significantly by 2038. Because of the displacement of coal generation, the Western Interconnection becomes more dependent on generation in the western Mountain and the Southwest regions to meet energy needs, and the eastern Mountain region switches from a net exporter to a net importer.

Demand in California continues to be a significant factor impacting the Western Interconnection. Transmission paths with high utilization include those that facilitate transfers from the western Mountain and Southwest regions to California and the eastern Mountain region and those that support transfers from the Northwest to California. The increase in solar generation in California has resulted in bidirectional flows on some of these congested paths, sending energy in the opposite direction when solar production within California is high. Path congestion occurs during periods of heavy ramping or during energy deficiency periods in California. While periods of congestion are shorter now given the bidirectional nature of power flows, they are of increased criticality for reliability (Lauby 2022). See Section IV.c. Qualified Paths for a more detailed discussion on congested paths.

California expects to interconnect offshore wind projects within the next several years. CAISO evaluates transmission needs for both the Humboldt and Morro Bay wind energy areas, located in the northern and central parts of the California coast, respectively. The Humboldt area has especially limited transmission infrastructure, and CAISO projects the need for two 500 kV AC lines and an HVDC line. CAISO is considering both overland and undersea options for the Humboldt HVDC cable (CAISO 2022b). Similar discussions are ongoing about interconnection needs for potential offshore wind development off the Oregon coast in the Northwest (NorthernGrid 2023).

## Texas anticipates major east–west in-state congestion as demand grows

ERCOT assesses transmission congestion for a range of future scenarios in its *Long-Term System Assessment* (ERCOT 2022c). The assessment finds that projected growth in renewable energy and electric vehicle adoption results in a shift in scarcity hours to later in the day, and that the system faces transmission limitations both in the parts of Texas with significant renewable generation capacity, like West Texas, as well as on paths into demand centers, like Houston (ERCOT 2022c). The West Texas Export Interface represents the most significant congestion constraint on ERCOT's system (ERCOT 2022d). To alleviate this challenge, ERCOT is considering increased capacity in the West, including a 1.5 GW HVDC line, as well as improvements closer to demand centers (ERCOT 2022b; ERCOT 2022c). ERCOT also notes that the Dallas-Fort Worth area experiences substantial congestion in the Current Trends scenario because of local load growth and new generation to the Northwest (ERCOT 2022c). Other congestion challenges are anticipated throughout the state based on expected retirements, new capacity, and changes in demand patterns.

## Alaska has limited transmission transfer capacity between generation and major load centers

Alaska's Railbelt power system has two critical interties with limited transfer capacity. The Alaska Intertie, a 78 MW-rated transmission tie, interconnects service regions to the north with southern utilities, and the Kenai Intertie, a 75 MW-rated transmission tie, interconnects the Kenai Peninsula to service areas to the north (Denholm et al. 2022b). Service regions interconnected through the interties maintain sufficient generation reserves and can operate largely independently due to limited transfer capacity and the potential for intertie failures to lead to system-wide transmission outages. AEA's *Railbelt Transmission Plan* finds the need to increase transfer capacity for both the Alaska Intertie and the Kenai Intertie (AEA and EPS 2017). Most recently, AEA (2022) describes that planned deliverable capacity improvements to a hydroelectric generation facility on the Kenai Peninsula in Alaska providing roughly 10% of total annual electrical energy used by Railbelt electric utilities will require transmission upgrades to reduce constraints and increase capacity exports from the Kenai Peninsula to the north.

Outside of the Railbelt service region, rural Alaskan communities are served largely by stand-alone microgrids. Across the state, there are more than 150 isolated microgrid systems that are not interconnected with the Railbelt or other rural utilities (Lovecraft et al. 2023). The vast majority of these systems rely on imported diesel fuel to meet electrical, space and water heating, and transportation requirements. Conditions in many rural villages, however, can make road transport of diesel fuel infeasible, causing diesel prices in areas requiring air or barge fuel delivery to be up to four times more expensive than fuel delivery in areas within Alaska with road transport access (Allen et al. 2016).

EPA (2020) notes that one method to reduce diesel consumption in rural Alaska is to construct electrical interties between isolated communities. Multiple studies have also been conducted to assess the potential for new transmission to interconnect rural communities to the larger Railbelt transmission system. A recent example includes a technical feasibility assessment of the development of a Roadbelt Intertie to interconnect islanded road system power utilities east of the Railbelt system, creating an additional transmission parallel to the existing Alaska Intertie (Ahtna and EPS 2020). The analysis demonstrates the project is feasible and has the potential to increase power transfers over time with the integration of new generation sited along the corridor. Stakeholder feedback suggests the project would potentially reduce power costs for rural communities, support regional economic development opportunities, increase U.S. Department of Defense facility resilience, and increase electric power reliability throughout the Alaska road system. Ahtna and EPS (2020) note that stakeholders in Alaska have studied the potential for increased transmission interconnection east of the Railbelt for over three decades and references 13 studies conducted since 1989 that relate to the proposed Railbelt Intertie.

## Isolated transmission systems in Hawaii are reaching capacity

Hawaii's six main islands each have their own electric grid without any electrical interconnections between islands. Utility service providers for Hawaii island, Oahu, Maui, Lanai, and Molokai find existing transmission infrastructure on each island is approaching capacity

limitations and will require additional transmission capacity as the islands continue to integrate renewable resources through ongoing and future procurement necessary to meet state clean energy goals (Hawaiian Electric 2021). KIUC (2023a) anticipates that Kaua'i will also require additional transmission to support future reliability needs and to mitigate outages associated with insufficient transmission capacity in its remote North Shore region.

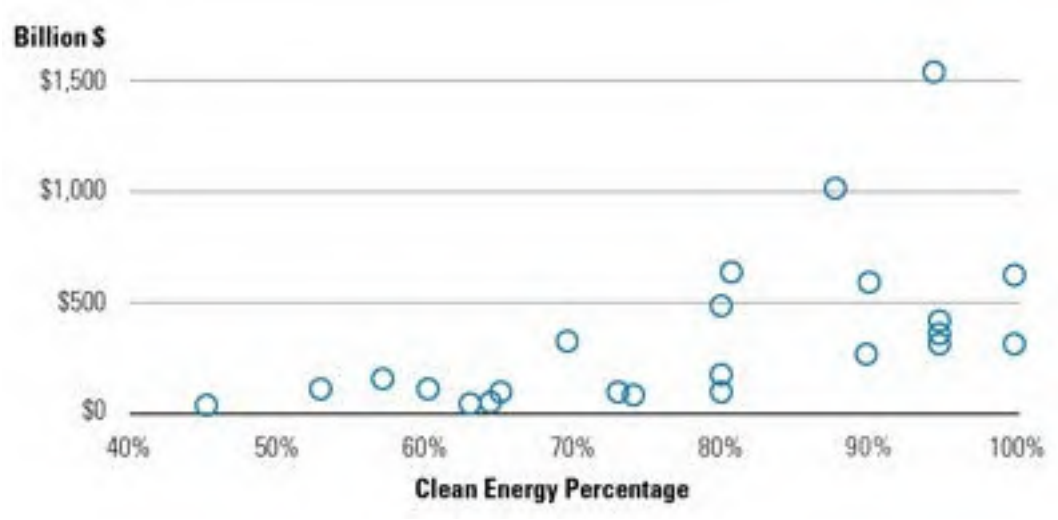
# V.c. Generation and Demand Changes

## New transmission will be needed to access many clean energy resources

Many reports surveyed cite access to clean energy resources for electricity production as a significant driver of transmission need. Numerous sources, including Brinkman et al. (2021), Bloom et al. (2020), Novacheck et al. (2021), Ardani et al. (2021), Cole et al. (2021), Clack et al. (2020b), FERC (2020), MISO (2022a), MISO and SPP (2022), Xu et al. (2021), and Pfeifenberger (2021), discuss the need for expanded transmission infrastructure at the national and international levels to take advantage of the diversity of generation resources.

Increasing the diversity of both resource fuel-type and resource geographic location improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility and reliability of the grid. The reports reviewed also note other benefits of clean energy generation integration, such as lowered electricity prices and system costs, avoided climate damages, and air quality improvements for frontline communities.

Several studies cite a need for significant transmission expansion as clean energy penetration increases. Most of these studies, including NERC (2021), indicate that expanding transmission will especially improve VER integration. Transmission planning entities are developing long-term assessments of regional transmission upgrades, sometimes stretching 15 to 20 years into the future. These plans are motivated by shifts toward greater renewable energy generation amid fossil fuel generation retirements, changes in demand patterns, and a need to increase intra- and interregional capacity, especially as new generation may not be located near retiring generation or load centers. Building transmission across regions and transmission between regions enables the system to take advantage of the geographic and temporal diversity of energy generation, particularly from wind and solar resources, for which abundant production in one region can help compensate for low production in another in times of need. Figure V-6 shows growing transmission investments associated with increasing clean energy generation.




*Source: Department of Energy (DOE 2022a), modified by author in June 2023.*

***Figure V-6. Summary of transmission investments estimated by several studies that enable differing levels of clean energy generation.***

In many cases, renewable generation increases will require upgrades to transmission capacity, which can involve modifying existing lines in addition to or instead of new construction (ISO-NE 2022b). Clack et al. (2020b) demonstrate that expanding transmission infrastructure to access low-cost renewable energy is a reliable, cost-effective way to reduce emissions, increase consumer savings, and stimulate electric-sector job creation. The authors find that significant amounts of new high-capacity transmission will be required regardless of the cost of renewables. In contrast, Phadke et al. (2020) find that low-cost generation technologies can reduce the amount of interregional transmission needed to connect high-quality renewable resource areas to load regions, which are often distant from one another. The authors explain that improved technology can access lower-quality resources and storage sited closer to load (Phadke et al. 2020).

Multiple long-term transmission plans conducted by regional planning entities identify the need to move new renewable energy generation from remote or distant areas to load centers (CAISO 2022b; ERCOT 2022b-d; MISO 2022a; NYISO 2022a). Retiring fossil fuel generation often is located closer to population centers, but renewable generation often is located far from retiring generation facilities and therefore cannot rely on the same transmission infrastructure. ERCOT (2022b) notes that 60% of the planned inverter-based resource additions to ERCOT's system are located in West Texas, which is a significant distance from demand centers in the eastern portion of the state. MISO (2022a) describes similar challenges as some planned renewable generation in the Midwest lacks adequate connection to demand centers. Like ERCOT, MISO is considering HVDC options. Tranche 1 of MISO's LRTP also proposes 18 new 345 kV lines that improve system-wide reliability and enable greater renewable penetration while delivering greater benefits than costs (MISO 2022a).

National studies, such as Ardani et al. (2021), Bloom et al. (2020), and others, also find a need for significant transmission expansion with increasing clean energy penetration. In a

decarbonization scenario targeting a 95% reduction in emissions on the U.S. electric grid from 2005 levels by 2035, Ardani et al. (2021) show that by 2050, transmission capacity expands by 60% (86,000 GW-mile [GW-mi])[44] relative to a reference scenario. Additionally, Cole et al. (2021) analyze scenarios of a wide range of power system futures and generally find that scenarios with higher levels of emission abatement correlate with higher levels of renewable generation deployment and increased levels of transmission development.

Clack et al. (2020b) find modeling scenarios with strong carbon-reduction policies result in approximately 140,000 GW-mi of new interstate transmission, whereas scenarios with weak carbon-reduction policies for cases with high solar and high wind generation deployment result in approximately 100,000 GW-mi and 70,000 GW-mi of new transmission, respectively. Clack et al. (2020b) also show that the amount of transmission capacity required for integration varies with the type of technology. Moving from weak to strong carbon cases under the high solar deployment case results in greater incremental transmission investment compared with moving from weak to strong carbon cases under the high wind generation deployment case. Presumably, this difference is because increased solar generation deployment in the Southeast requires additional transmission capacity to export excess solar energy production during the daytime and to import wind energy production at night.

Xu et al. (2021) investigate the renewable generation and transmission requirements needed to achieve 70% clean energy for the U.S. electric grid by 2030 by modeling different transmission designs. The authors model four distinct transmission designs that include AC only and combined AC and HVDC transmission upgrades. In all cases, AC capacity relative to current capacity increases from about 23% to 36%. The broader reach of the design with a new 16-line HVDC network connecting all three interconnections with no change in existing HVDC converter station capacity enables southeastern U.S. states to import power from elsewhere in the country. Regardless of transmission design, the authors find that certain U.S. transmission corridors require large capacity upgrades. These common upgrades, approximately 56 terawatt-miles (TW-mi), make up at least half of upgrades for each design. Regional upgrades common across all transmission designs are found in the Southeast, Midwest, and Texas. The most common interregional transmission needs are found between the Plains and Delta regions and between the Southeast and Florida. An HVDC network connecting the Eastern and Western Interconnection seam can also reduce the cost of resources required to meet clean energy goals. For example, the need for transmission upgrades in the Eastern Interconnection is reduced because the Western Interconnection exports more clean energy (primarily solar) to the Eastern Interconnection (Xu et al. 2021).

In a scenario with constrained carbon dioxide emissions (80% reduction in carbon emissions from 2005 levels in the United States and Mexico, and 92% reduction in Canada by 2050), Brinkman et al. (2021) find even more transmission is necessary because variable resource

[44] GW-mi is not a commonly used unit in the industry, but is the unit used by capacity expansion modeling results. For comparison, a 100-mile, 345 kV rated transmission line has an estimated carrying capacity of 860 MW, equivalent to 86 GW-mi (NRRI 1987). A 200-mi 500 kV line has a carrying capacity of 1,320 MW, equivalent to 264 GW-mi (NRRI 1987). *See* Table VI-2 for a comparison of carrying capacities and nominal voltage ratings for different length transmission lines.

costs are higher, forcing transmission buildout to more resource-rich regions farther from load centers. The authors note that their findings do not demonstrate that it is impossible to achieve renewable contribution levels or reliable future grids without extensive new transmission builds, but rather that those scenarios, if feasible, would come at a higher cost. In their modeling to estimate the system cost of electricity in a 100% renewable U.S. power system, Brown and Botterud (2020) conclude that transmission capacity expansion and better coordination between regions can reduce the cost of decarbonization by almost half compared with a case with no interstate or interregional transmission investments, reinforcing the idea that decarbonizing without increasing transmission will be more costly.

In a WECC assessment of the requirements to meet clean energy goals by 2040 within the Western Interconnection, Bailey (2022) emphasizes that transmission constraints are of significant concern at a 100% clean energy level and additional transmission investments should be considered early because new lines take many years to plan, site, approve, and build. Larson et al. (2021) argue that planning, siting, and construction of new lines should be a priority in the 2020s to meet the large need for new transmission projected for the 2030s.

CAISO's (2022b) *20-year Transmission Outlook* identifies specific 500 kV AC and HVDC lines, transformers, substations, and converter stations required to upgrade California's existing bulk transmission footprint and to deliver new offshore wind development, out-of-state wind resources, and solar generation. The recommended projects help to avoid overload and voltage collapse scenarios forecasted in CAISO's models. CAISO notes that given its interconnection queue length, transmission planners are facing obstacles to adding necessary resources to the grid.

Hildebrandt et al. (2021) identify a series of transmission system improvements to integrate the expected generation resources needed to meet the goals of California's Senate Bill 100 (California Legislature 2018), which sets a target that 100% of California's retail electricity be met by renewable and zero-carbon sources by 2045. Hildebrandt et al. (2021) estimate the cost of transmission investments to integrate renewable resources at $30.5 billion, comprising $10.74 billion in upgrades to the existing CAISO footprint, $8.11 billion for offshore wind integration, and $11.65 billion for out-of-state wind integration. The authors report that accommodating 4.7 GW of wind resources from Wyoming and 5.2 GW from New Mexico will require additional incremental transmission builds. Hildebrandt et al. (2021) also show the importance of addressing transmission infrastructure needs in California, stating that rapid increases in renewables are outpacing projections. For example, CAISO's 2020–2021 transmission plan is based on the addition of 1,000 MW per year of new resources, while the forthcoming 2022–2023 transmission plan is expected to be based on 4,000 MW per year.

Similarly, Simonson et al. (2021) note the high number of solar, wind, and storage projects in generation interconnection queues seeking to interconnect to the grid in Utah in the Mountain region, and the potential for additional future renewable resource development due to municipal and county renewable energy goals within the state. The study finds that anticipated renewable generation development, in combination with load growth, created the need for the Utah transmission system to accommodate between 1.7 and 2 GW of new resources by 2025, between 3.5 and 5.1 GW by 2030, and between 5.5 to 9 GW of new capacity by 2040. The

authors note that transmission buildout in the state will not only serve to accommodate resource interconnection but is also necessary to reduce congestion and constraints on key paths.

In MISO's *Renewable Integration Impact Assessment*, Prabhakar et al. (2021) conclude that renewable penetration beyond 50% in the MISO region can be achieved with coordinated action. The assessment identifies new and changing risks and system needs, including insufficient transmission capacity. Furthermore, transmission infrastructure investments, especially the higher voltage lines, increase with increasing renewable penetration. Expansion of new transmission lines rated 161 kV and below is highest at the 30% renewable generation level at 1,700 circuit-miles, decreasing to 500 circuit-miles at 50% renewable generation. On the other hand, expansion of new transmission lines rated 230 kV and higher ranges from 700 circuit-miles at 20% renewable generation to 6,000 circuit-miles at 50% renewable generation. In addition, new HVDC lines were identified at 30% renewable generation levels and higher.

Dimanchev et al. (2020) note that meeting existing state climate policy targets in New York and New England will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Québec, Canada. According to the study, in a low-carbon future, it is optimal to shift the utilization of the existing hydropower and transmission assets away from facilitating one-way export of electricity from Canada to the United States and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation (Dimanchev et al. 2020). The authors find that doing so can reduce power system costs by 5%–6% depending on the level of decarbonization. The cost-optimal use of Canadian hydropower is as a complement, rather than as a substitute, to deploying low-carbon technologies in the United States. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy.

Jones et al. (2020) similarly note in a regional analysis conducted for a Massachusetts study that Canadian hydropower is an essential element of regional balancing. In their study, bidirectional flow of electricity enabled the Québec hydropower system to transition into the role of a "battery," storing excess wind and solar generation for the New England region. The use of a hydropower system as storage depends on the timing of renewable production and demand on both sides of the U.S.-Canada border (Jones et al. 2020). Total net-imports into Massachusetts from Québec declined after 2035 in the analysis. The study estimates that an additional 4.1 to 7.1 GW of new transmisison capacity between Québec and New England would be required.

In the Southeast, utility planning and state regulatory processes have also highlighted the need for additional transmission to accommodate a shift in the generation fleet and to meet decarbonization targets. Duke Energy's *2022 Carbon Plan*, for example, has identified the need for significant transmission investment on an aggressive timeline to accommodate incremental generation resource additions and coal plant retirements necessary to meet carbon emission reductions and carbon neutrality targets established by North Carolina Session Law 2021-165 (Duke Energy 2022). The North Carolina Utilities Commission's *Carbon Plan* order urges Duke—in light of the magnitude of potential future transmission expansion—to be vigilant in its

participation in the Southeast Regional Transmission Planning. and coordination with PJM to explore all possible efficiencies (NCUC 2022).

In Alaska, Denholm et al. (2022b) assesses the techno-economic feasibility of an 80% renewable portfolio standard within the Railbelt region. The study finds that additional transmission will likely be required to connect new renewable resources necessary to reach an 80% renewable portfolio standard. Additionally, all scenarios considered identify the need to significantly upgrade the Alaska Intertie interconnecting utilities in the Railbelt's northern footprint with those located south of the intertie. Allen et al. (2016) describes solutions for integrating clean energy resources in rural areas outside of Alaska's Railbelt region, which have historically been powered by localized diesel-fired generation, including additional transmission interconnection between rural utilities where feasible, among other solutions. The report notes, however, that in instances where geography and distance prevent interconnection feasibility, the interconnection of variable renewable energy in rural villages may require a suite of alternative transmission solutions, including flexible load and storage, to capture any excess generation and prevent curtailment.

In Hawaii, Hawaiian Electric (2023a) finds that transmission network expansion is critical for Hawaii island, Oahu, Maui, Lanai, and Molokai to be able to integrate sufficient renewable resources required for the state to reach its 100% renewable by 2045 renewable portfolio standard target. In addition, utility service providers continue to work with communities and landowners to identify renewable energy zones that are prime for renewable resource development but may be far from existing transmission infrastructure or require robust transmission upgrades to accommodate the generator interconnection (Hawaiian Electric 2023a). Hawaiian Electric (2023b) also anticipates reliability concerns due to high levels of inverter-based renewables integration, noting future systems with increased inverter-based resources will experience lower physical inertia and more complex dynamics during system events. To address potential concerns, Hawaiian Electric (2023b) finds that grid-forming inverter-based resource[45] integration is a critical component to reduce the adverse impacts (e.g., load shedding) of incorporating higher levels of renewable generation. Hawaiian Electric (2023a) notes promising performance of grid-forming resources on the island of Kaua'i.

## Reduced curtailment of available economic generation resources can be achieved with additional transmission

Various reports reviewed as part of this literature review, including Brown and Botterud (2020), Clack et al. (2020b), Xu et al. (2021), Bailey (2022), and FERC (2020), cite transmission expansion as an effective means of avoiding or reducing generation curtailment. Several reports maintain that curtailment is caused primarily by generation oversupply and transmission constraints.

[45] Historically, inverters were not able to operate independently of the power grid they were connected to and could not provide essential services to bring the power grid back online following a disturbance. These inverters are referred to as "grid-following," given their dependence on the grid. "Grid-forming" inverters can operate independently and provide essential services to help the grid ride through a disturbance. See Lin, et al. (2020) for more information about grid-forming, inverter-based resources.

Curtailment is often cited as a concern, as it may challenge objectives to efficiently integrate renewables to reach electric-sector decarbonization goals, to realize the full benefits of renewable generation investments, and to achieve further pollution reduction. Xu et al. (2021) note, however, that some amount of curtailment is inevitable—even with a perfect transmission network—because of the patterns of solar and wind availability.

In a study examining the potential economic value of increasing power transfers between the Eastern Interconnection and Western Interconnection, Bloom et al. (2020) model four different transmission designs that include HVDC transmission expansion co-optimized with generation investments and AC transmission investments. The authors report that the curtailment of renewable generation ranges from 11% to 15%, with congestion on AC transmission lines as the main driver. They note, however, that understanding the tradeoffs among curtailment, transmission, and other options requires additional analysis. Pfeifenberger (2021) quantifies curtailment reductions, estimating that for grids with 10%–60% renewable generation, regional diversification through the transmission grid results in curtailment reductions ranging from 45% to 90%.

Ardani et al. (2021) further state that curtailed solar and wind represent low-cost, zero-carbon power that can be used to supply new demand or produce low-carbon fuel. Using this curtailed energy, however, will require co-locating solar resources and low-carbon fuel production, developing adequate transmission connections, or identifying new demand resources that can make economic use of the variable curtailed solar. The report also notes that curtailment occurring during the operation of combustion turbines fueled by renewable energy sources is an indication of transmission congestion, which demonstrates the critical role of transmission in achieving a least-cost mix of resources.

Clack et al. (2020b) find that expanding continental-scale transmission across the eastern and western United States, as well as increasing ties to ERCOT and Canada, can also help reduce curtailment through greater geographic diversity of resources. Additionally, the authors note that electrification could help reduce curtailment if resource dispatch and wholesale electricity markets are coordinated.

Prabhakar et al. (2021) demonstrate transmission solutions substantially decrease wind energy curtailments at 40%–50% renewable penetration levels in the Midwest and Delta regions. The report notes that because transmission solutions have a lower effect on curtailment reductions at 50% renewable penetration level, transmission solutions have potentially diminishing returns at higher penetration scenarios.

Generation curtailments that are due to transmission constraints can also have reliability impacts. Goggin and Zimmerman (2023) and Massie and Toth (2023) suggest that additional interregional transmission capacity could have mitigated Winter Storm Elliott's impacts in the Southeast. Massie and Toth (2023) note that although wind generation in the Plains, Midwest, and Mid-Atlantic remained strong and consistent throughout Winter Storm Elliott, transmission limitations led to significant curtailment. Approximately 3 GW of wind curtailments occurred in SPP while TVA customers in the Southeast faced blackouts, and Massie and Toth (2023) suggest that additional transmission could have reduced these blackouts for TVA customers.

## Offshore wind potential is driving transmission needs, but offshore transmission networks require specific planning considerations to meet those needs

Offshore wind is poised to play a significant role in the country's decarbonization as it expands beyond the existing 42 MW of operational offshore wind capacity. As of May 2022, the project development and operational pipeline of wind energy has increased to 40,000 MW of planned offshore wind capacity (Musial et al. 2022). Shields et al. (2022) note that meeting the federal goal of 30 GW of offshore wind energy by 2030 could require 2,100 turbines and over 11,000 kilometers (km) of transmission cables.

Several aspects of offshore wind transmission can help unlock the country's significant wind energy potential. Offshore transmission planning is siloed (Pfeifenberger et al. 2023; Bothwell et al. 2021) and leads to transmission development on a piecemeal basis, resulting in inefficient outcomes. That is, transmission planning that accommodates for future offshore wind capacity installation rather than planning on a project-by-project basis can ensure a networked, more cost-effective solution in the long run. Additionally, interregional transmission coordination (Pfeifenberger et al. 2023; Douville et al. 2023; Bothwell et al. 2021) can be stymied by disparate state policies, as well as cost allocation and permitting issues. Technology development, integration, and standardization of HVDC transmission can unlock solutions that reduce environmental impacts and are more cost-effective (Pfeifenberger et al. 2023), while helping to advance the technological readiness of floating offshore wind (Douville et al. 2023). Finally, transmission infrastructure along the nation's coasts is insufficient to accommodate utility-scale injection of offshore wind. Shared offshore transmission will need to be developed and connected to the onshore system, which will require further analysis of topologies and their associated costs, benefits, and siting options (DOE 2023a).

Several studies discuss the unique transmission challenges associated with offshore wind integration in bringing generated power through the ocean to onshore terminals where it will be delivered to load. Looking at examples on the Atlantic is relevant, given that most of the 30 GW of offshore wind energy by 2030 is projected to be developed along the Atlantic Seaboard (Bothwell et al. 2021). Pfeifenberger et al. (2020a; 2020b) evaluate offshore transmission planning approaches for New England and New York, respectively. They find that an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of offshore wind resources compared with each offshore wind resource connecting to the onshore grid through a dedicated generator lead line. Pfeifenberger et al. (2020a; 2020b) find that designing and building the offshore grid with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

NYISO (2022a) acknowledges that the pace of renewable energy growth requires an increase in transmission development or there will be significant transmission constraints in New York. The most significant increase in future renewable generation curtailments will be experienced by offshore wind projects connected to Long Island where there is inadequate transmission capacity. The Long Island Authority Board of Trustees identified a transmission need for offshore wind to meet state climate goals (NYISO 2022a). In addition, the New York State Public Service Commission issued an order stating that offshore wind goals are driving the need for

additional transmission facilities to deliver at least 3,000 MW of offshore wind output from Long Island. Additional offshore wind injections will require local onshore transmission and distribution system upgrades on Long Island. Without further investment in transmission, Long Island could experience persistent and significant limitations to deliver renewable power to customers (NYISO 2022a).

ISO-NE, like other transmission planning authorities on the Atlantic coast, is expecting additions of significant New England offshore wind generation in the coming years. ISO-NE discusses a tradeoff between smaller and larger offshore wind interconnections (ISO-NE 2022b). For example, smaller interconnections involve lower transmission upgrade costs but higher generator lead costs, along with a greater number of HVDC converters and offshore connections. Conversely, larger interconnections are the opposite, with lower numbers of converters and connections but higher transmission upgrade costs (ISO-NE 2022b).

Pfeifenberger et al. (2020a) indicate that New England had contracted for over 3,000 MW of offshore wind generation at time of publication. A subsequent 3,600 MW of offshore wind generation could still be developed under the status quo, with each developer constructing a generator tie-line to an onshore point of interconnection. However, this existing approach is likely to require substantial onshore system upgrades far sooner than assumed. Selected projects connecting to the transmission system on Cape Cod, Massachusetts, already face up to $787 million in onshore transmission upgrades. Continuing this approach in the next set of generation procurements could lead to an additional $1.7 billion in onshore upgrades (Pfeifenberger et al. 2020a). This conclusion emphasizes the possible need for new infrastructure and coordinated planning.

ISO-NE's *First Cape Cod Resource Integration Study* (2021) identifies the transmission upgrades necessary to enable the interconnection of proposed new offshore wind resources to Cape Cod. This study finds that a new 345 kV line would enable another 1,200 MW of offshore wind generation to interconnect. This system upgrade would supplement the already-estimated 1,600 MW of proposed Cape Code offshore wind generation that has completed its interconnection studies. This 2,800 MW of total new offshore wind generation demonstrates the significant economic potential of offshore wind generation. At the same time, it is clear that the anticipated interconnections for offshore wind generation are likely to be much higher than assumed when planning the area's current grid infrastructure. In response to the growing interest in offshore wind generation, ISO-NE has developed a process for identifying common infrastructure needs and minimizing potential interconnection queue backlog resulting from the influx of proposed offshore wind generation.

Pursuing proactive, coordinated transmission planning solutions to offshore wind integration can reduce onshore grid upgrade costs, increase reliability, and reinforce existing regional onshore grids (Pfeifenberger et al. 2023). Research by Pfeifenberger et al. (2023) and Burke et al. (2020) also notes that long-term planning can improve efficiency and reduce environmental impacts by reducing the number of necessary points of interconnection, miles of transmission cables, and other physical infrastructure.

Given the complexities of integrating offshore wind along the Atlantic coast, the Department initiated the Atlantic Offshore Wind Transmission Study in 2021 to analyze how different

coordinated transmission solutions enable offshore wind energy deployment along the U.S. Atlantic Coast (*see* accompanying text box). Preliminary analysis indicates that connecting large volumes of offshore wind along the Atlantic Coast over the next several decades provides a unique opportunity to use interregional transmission links to reduce electricity production costs and bolster reliability and resilience onshore.

**DOE Work on Offshore Wind Transmission**

DOE is in the process of completing the Atlantic and West Coast Offshore Wind Transmission Studies. The studies evaluate multiple pathways to reach offshore wind goals through coordinated transmission solutions along the U.S. Atlantic and Pacific coasts under various combinations of electricity supply and demand while supporting grid reliability and resilience and ocean co-use. Researchers from the National Renewable Energy Laboratory and the Pacific Northwest National Laboratory are conducting these studies by creating multiple scenarios of interstate, interregional transmission topologies between 2030 and 2050.

National Renewable Energy Laboratory, Atlantic Offshore Wind Transmission Study, https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html.

Working in close coordination with the Atlantic Offshore Wind Transmission Study, DOE and the U.S. Department of the Interior published an interim draft of *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region* in September 2023. Key recommendations from the Action Plan involve improved environmental review and permitting frameworks, strong state leadership, empowerment of permitting agencies, thoughtful cost allocation practices, and consideration of NIETCs. Examples of Action Plan recommendations relevant to assessing and addressing transmission need include evaluating point-of-interconnection capacities and locations, clarifying NERC reliability standards around offshore transmission, considering interregional transfer capability minimums, and collaborating on federal-state aligned offshore transmission siting (DOE 2023b).

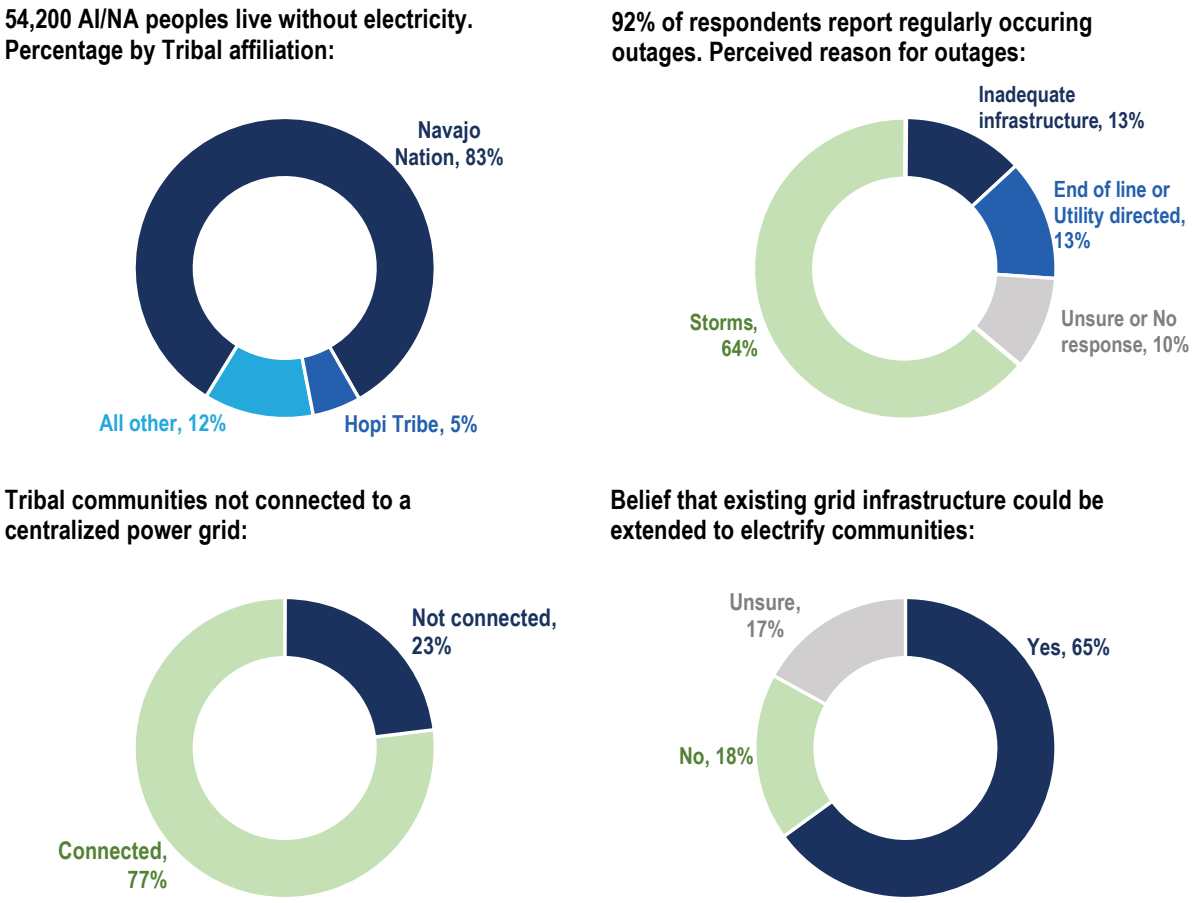
Given the topography of the U.S. Pacific coast, planners and researchers are looking at the development of floating offshore wind along the California and Northwest coasts. Grid planners in California and Oregon are investigating ways to integrate large offshore wind generators (CAISO 2022b; NorthernGrid 2023). Evolved Energy Research (2021) considers the complexities of integrating offshore wind along the Pacific Coast. The authors note that a substantial portion of investment in offshore wind in the Northwest is needed to meet both Oregon's current 2050 economy-wide target of 80% emissions reductions below 1990 levels and to enable exports of low-cost, high-capacity-factor clean electricity to other Western states (Evolved Energy Research 2021). The 20 GW of offshore wind projected to be built over 15 years would require a rapid scale-up of new supply chains and production capacity. A regionally integrated power grid is critical to enabling Oregon to take advantage of out-of-state clean energy resources, export power to other states, and efficiently plan for grid reliability. Regional grid integration will also be key to efficient decarbonization throughout the West.

## Tribal lands have unique energy and transmission needs

Indian Tribes have expressed a significant need and interest in developing their own energy resources, implementing energy efficiency and renewable energy technologies, stabilizing energy costs, and spurring local economic development, especially when jobs can be provided to Tribal members. Lack of tribe-specific data has historically prevented quantifying the current energy state in Indian Country and hampers justifying additional resources, however (Johns et al. 2022).

The Department is currently conducting a survey of Tribal access to reliable electricity as directed by the Fiscal Year 2021 Consolidated Appropriations Act. Preliminary survey results suggest that over 54,000 American Indian and Alaska Native (AI/NA) peoples do not have access to electricity today, most notably the Navajo Nation and Hopi Tribe (Johns et al. 2022). Among those who do have access to electricity, respondents overwhelmingly (92%) reported regular electricity outages, often because of inadequate infrastructure or because they are serviced by a single power line that lacks redundancy. Nearly a quarter (23%) of all survey respondents do not have access to a centralized power grid, but many of those do have access to electricity via a local microgrid. The large majority (65%) of respondents believe that existing grid infrastructure could be extended to Tribal communities to provide more reliable electricity. Figure V-7 summarizes these preliminary findings (Johns et al. 2022).

Indian Country contains vast untapped energy resources. While a wide variety of energy resources exist on Tribal lands, increasing vulnerabilities due to climate change have resulted in a rising demand for clean energy generation (Jones et al. 2022). Renewable energy technologies provide opportunities for diversification, energy independence, environmental sustainability, and new revenue streams for Native American Tribes, Alaska Native villages, and Alaska Native corporations (Milbrandt, Heimiller, and Schwabe 2018). Many Tribal lands are located in areas that have abundant renewable energy, such as wind, solar, and biomass. Over 9% of the nationally available renewable energy resource is found within 10 miles of federally recognized Tribal lands (Brooks 2022). Transmission is key in accessing these potential generation resources.




*Source: Department of Energy (Johns et al. 2022).*

*Note: "AI/NA" stands for American Indian and Alaska Native.*

***Figure V-7. Preliminary survey results demonstrating lack of reliable access to centralized electricity on Tribal lands.***

In Milbrandt, Heimiller, and Schwabe (2018), the authors estimate the technical and economic potential for renewable energy development on Tribal lands to support American Indian Tribes and Alaska Natives in decision-making as they evaluate technologies, potential scales of development, and economic viability. The resources analyzed include wind, solar photovoltaic and concentrating solar power systems, woody biomass, biogas, geothermal, and hydropower. The analysis shows that the utility-scale technical potential of these resources on Tribal lands is approximately 6.5% of the total national technical potential. By comparison, federally recognized Tribal lands make up approximately 5.8% of the contiguous U.S. land area (Milbrandt, Heimiller, and Schwabe 2018).

Milbrandt, Heimiller, and Schwabe (2018) find the economic potential[46] for Tribal land-based wind exceeds 1 GW, which could produce more than 3 TW-hour (h) of electricity generation annually. For utility-scale photovoltaic systems, there is more than 61 GW of economic potential, which could produce nearly 116 TWh of electricity generation annually. There is potential for distributed wind and solar in almost all Tribal areas; however, in low-resource areas the resulting levelized cost of energy is high and might not be competitive with grid electricity prices. Broadly, Tribal lands in the western United States and the Plains regions contain high-quality resource potential for wind, even at lower turbine hub heights. In the eastern and southeastern United States, wind opportunities are more limited. Increased solar resource availability makes distributed solar photovoltaic systems more productive for Tribes in the southern United States. Other renewable technologies did not show positive economic potential on Tribal lands based on the set of assumptions used in Milbrandt, Heimiller, and Schwabe (2018).

Resources that did not show economic potential in Milbrandt, Heimiller, and Schwabe (2018) could be revisited as the relative costs of renewable energy technology and market prices change. This constantly changing cost profile is particularly important in determining the relative value of renewable energy compared with other replacement sources of energy (Milbrandt, Heimiller, and Schwabe 2018). Future improvements to economic potential assessments on Tribal lands include incorporating both in-region and out-of-region transmission costs and other policy drivers such as energy independence, reliability, environmental benefits, renewable portfolio standards, and any sensitivities to tax-oriented policies.

Access to the transmission system is required to bring the economically viable generation resources to market. Where some Tribal lands are well covered by the transmission system, some have limited or no access to high-voltage lines. The Department has funded the Geospatial Energy Mapper to locate potential areas of low-carbon energy development. This tool also includes an interactive map of the existing transmission system and Tribal lands to see where overlaps do and do not exist (*see* accompanying text box). Figure V-8 shows the transmission system near the Tohono O'odham and the Houma Tribal lands—two areas with very different transmission coverage—using the Geospatial Energy Mapper tool. Similar maps could be made using the tool for anywhere in the contiguous United States.

In addition to transmission access, there are significant financial, infrastructure, and human capacity barriers that hinder Tribal energy development. Federal Indian law and jurisdictional uncertainties and complexities limit private investment and impede energy development on Tribal lands. Complicated Federal application processes and funding gaps limit access by American Indian and Alaska Native communities (Jones et al. 2022).

[46] Whereas *technical potential* defines the amount of energy of a particular resource that could be converted into electricity given current technologies, the *economic potential* defines the amount that is financially viable to convert given technology costs and projected project revenue.

**DOE Work on Mapping Energy Resources**

The Department has funded the development of the Geospatial Energy Mapper (GEM) tool at Argonne National Laboratory. GEM provides mapping data and analysis tools for planning energy infrastructure in a geographic context. GEM is an interactive web-based decision support system that allows users to locate areas with high suitability for clean power generation and potential energy transmission corridors in the United States.

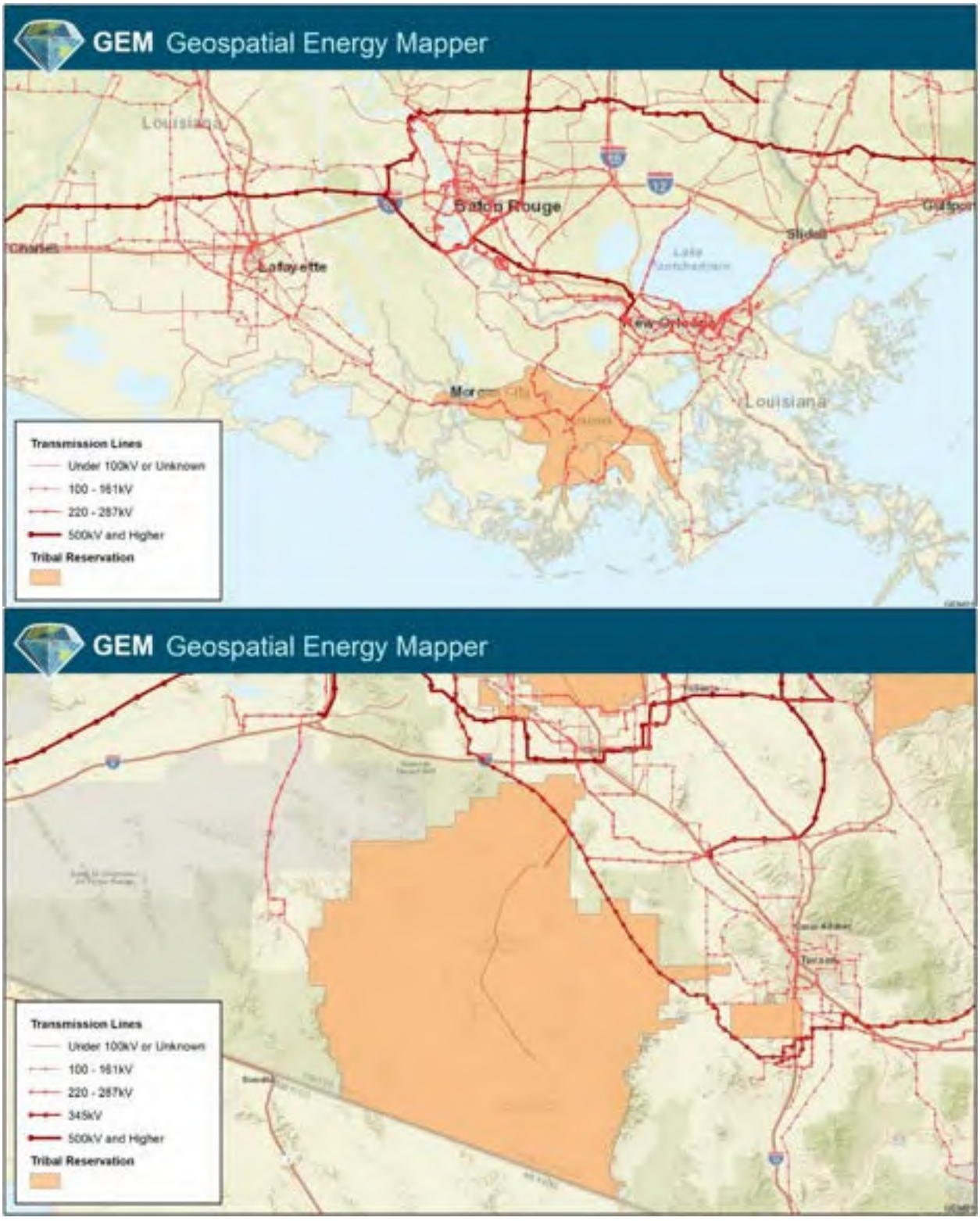
Argonne National Laboratory, Geospatial Energy Mapper (GEM), https://gem.anl.gov/.

## Load growth will require more transmission

Load growth necessitates additional transmission capacity to transfer more power to consumers. In instances when load growth occurs in existing load centers, capacity expansion of existing transmission infrastructure through line upgrades or rebuilds, or through advanced transmission technologies, can help meet electricity needs. In cases where load growth may occur in areas far from existing load centers, potentially due to growth in emerging industries, new transmission wires may be required to deliver electricity. System operators are preparing for significant load growth in the coming decade, including in regions where important advances in energy efficiency resulted in near historic flat electricity demand (Gledhill 2021; ERCOT 2021b; PJM 2023a).

Several studies identify emerging industries with high electricity use—such as data centers, chemical production, hydrogen production, and direct air capture—and electrification of end-use devices as another major driver of transmission investments. Electrifying technologies and systems that currently run on fossil fuel sources are important in enabling economy-wide decarbonization to mitigate the impacts of climate change and improving local air quality that impacts human health, particularly for frontline communities.

ISO-NE's *Future Grid Reliability Scenarios* study (ISO-NE 2022a) notes that, in addition to changes in electricity supply, regional goals and legislation regarding heating and transportation will also change the way electricity is used throughout New England over the next decade and beyond. Heating and transportation will become further electrified. Policy initiatives to replace building heating systems currently powered by wood, oil, propane, or natural gas to electricity will have a significant impact on the power grid. Replacing these building heating systems with electric-powered air-source or ground-source heat pumps will significantly increase the total demand on the New England grid. The replacement of gas and diesel-powered vehicles with electric vehicles will also increase overall system demand. Heating and electrification demand envisioned by one of ISO-NE's future scenarios is an exponential increase from current trends. In addition to the overall increase in demand, daily electrical system demand patterns will also change.




*Source: Created by Jim Kuiper at Argonne National Laboratory using the Geospatial Energy Mapper tool (2022).*

***Figure V-8. Overlap of the existing transmission system with the Houma (top) and Tohono O'odham (bottom) Tribal lands.***

An increase in electrification could present reliability risks without proactive transmission planning (NYISO 2022b; PJM 2022). NYISO's *Reliability Needs Assessment* observes that New York reliability risks are anticipated to increase during winter months by mid-2030 as the grid is becoming winter-peaking due to space heating and transportation electrification (NYISO 2022b). PJM notes that demand growth in the winter is anticipated to more than double compared with summer demand growth due to increased electrification, causing a shift in seasonal and hourly risk in the winter (PJM 2022). Some major metropolitan areas are anticipated to experience significant load growth caused by shifts in local decarbonization policies that will impact the transmission and distribution networks. In New York City, for example, reliability margins are already at risk due to limited generation and transmission, while peak demand is expected to rise significantly due to commercial and residential growth (NYISO 2022b). Because of New York City's narrow reliability margins, it is possible that increased demand, significant delays in projects in Champlain Hudson Power Express development, or additional generator deactivations could all create deficiencies (NYISO 2022b).

Brinkman et al. (2021) simulate a scenario representing the electrification of heating, transportation, and other end-use energy demands in North America, such that electricity loads in 2050 are nearly double those in 2020. The result is significantly more transmission investments, with the greatest increase in investments at the intranational level. Under this scenario, transmission expansion within the contiguous United States is approximately 195 GW, over three times the business-as-usual scenario. Expansion between the United States and Mexico is approximately 8 GW and between the United States and Canada is approximately 20 GW.

FERC (2020) similarly reports on Brattle Group estimates that increased future electrification efforts will stimulate substantially more transmission investment compared with historical levels. The Brattle Group study quantifies these transmission needs, finding that the United States will need an average transmission investment of $3–$7 billion per year through 2030 due to electrification, in addition to maintenance and renewable integration investments.

Clack et al. (2021) points out that investments in the distribution system, and not just the transmission system, will be crucial in high electrification futures. In Clack et al. (2021), the largest share of cost in 2050 is distribution system investments, which are required to address system needs due to economy-wide electrification. In Hawaii, Hawaiian Electric (2023a) finds that new housing and electrification of load required to meet statewide housing and decarbonization goals in Hawaii may require modernization of the distribution system.

## V.d. Alternative Transmission Solutions

Alternative transmission solutions can be deployed on the existing grid to increase transmission capacity, improve operational flexibility, and manage congestion and curtailment. Alternative transmission solutions like energy storage; DERs; advanced transmission technologies, including GETs and advanced conductors and cables; and microgrids are example technologies that can serve some of the same purposes as traditional transmission solutions, but these technologies

are unlikely to meet the full scope of national transmission need on their own and do not obviate the need for new transmission infrastructure.

Strategic planning to site storage and generation close to load centers could also help mitigate the need for traditional transmission solutions. For example, DERs could help meet demand locally. Demand response is another technology with the potential to limit electricity demand when transmission is constrained. Implementing these generation- and demand-based solutions requires careful planning from utilities, state, and local officials to ensure resource adequacy and minimize risks but can provide significant value that outweighs costs when properly deployed. These alternative transmission solutions are discussed in more detail below.

## Energy storage can aid the transmission system by balancing generation and load

Energy storage can serve as a grid asset to support higher degrees of variable energy on the system by shifting load across hours or days, smoothing seasonal peaks, and providing grid services. Prabhakar et al. (2021) find that pairing storage with renewables and transmission helps optimize grid operations in the Midwest and Delta regions. Without adequate transmission capacity, however, storage might not contribute sufficiently to achieving penetration targets. Similarly, Kemp et al. (2023) find that hybrid variable renewable energy-plus-storage plants can help reduce the need for transmission when sited near congested load centers, particularly when hybrid plant characteristics allow for the ability to charge from the grid and include storage technology with lower degradation costs.

In their storage sensitivity modeling, Prabhakar et al. (2021) indicate that even with large additions of storage to the MISO system, there is a limited change to transmission needs. More specifically, their modeling shows that beyond an incremental 12.1 GW of 6-hour storage at 40% renewable penetration, there is little change to transmission needs. In contrast, Bailey (2022) finds that adding battery storage resources can help offset the need for new transmission expansion in integrating renewables onto the grid.

Furthermore, Clack et al. (2020b) demonstrate that storage complements transmission by increasing the utilization of transmission lines. Jorgenson et al. (2022) also find that storage increases utilization of some transmission lines, as demonstrated by reductions in observed congestion, while reducing the congestion observed on other lines. Exactly how storage impacts nearby transmission by increasing or decreasing usage depends on the local conditions.

For instance, in New England, large quantities of new energy storage, primarily batteries, could be used as a solution to maintain grid reliability in a renewable-dominant landscape (ISO-NE 2022a). The ISO-NE (2022a) analysis finds that modeling storage with the objective of price arbitrage does not fully address the needs of the overall future power grid. Current reliability models may not be able to capture long dispatch periods and the reserve services that storage is able to provide, which will become increasingly important with larger VER penetration.

Allen et al. (2016) finds that thermal and battery storage have the potential to facilitate efficient renewable energy integration into rural Alaskan systems. In the absence of sufficient transmission interconnection, certain rural utilities have found storage able to provide a buffer for variable wind resource integration on system frequency and voltage levels. In Alaska's

Railbelt region, AEA and EPS (2017) find that battery storage deployment near Anchorage would help alleviate short-term overloads in the event of a Kenai Intertie transmission outage. The report notes that storage dispatch would provide time for generators to the north of the intertie to redispatch following a contingency event as well as reduce or eliminate the need for load shedding.

## High penetrations of distributed energy resources can shift regional transmission needs

Clack et al. (2020a; 2020b; 2021) and other studies comment on the role of DERs[47] in a clean electricity system. Clack et al. (2020a) use a model that allows for the incorporation of a detailed representation of the distribution system and disaggregation of DER technologies, providing insights into the interface of the distribution and transmission systems. Their model enables comparisons between scenarios with a traditional planning approach augmented with DER co-optimization and scenarios that exclude DER co-optimization.

Clack et al. (2020a) also evaluate the potential value of DERs in lowering costs across the electricity system and promoting clean electricity goals. The study models four scenarios—a business-as-usual scenario with and without DER co-optimization and a clean energy standard scenario also with and without DER co-optimization. The authors find that transmission expands at a similar rate in all scenarios until 2035. In the clean energy standard scenarios, transmission expands rapidly after 2035, when significant changes in generation resource mix required to meet clean energy goals start to occur. Additionally, the study finds that DER co-optimization results in key geographic differences in the location of transmission builds. Compared with scenarios without DER co-optimization, scenarios with DER co-optimization require higher transmission buildout in the states in the Southeast to help integrate VERs. A similar trend, although to a lesser extent, occurs in the states in the Southwest that have higher solar generation. States in the northeastern regions require a higher buildout of transmission in scenarios without DER co-optimization to support utility-scale generation developed in those scenarios. In general, total transmission expansion is similar in the two business-as-usual scenarios. In the clean energy standard scenarios, total transmission expansion is slightly higher in the scenario with DER co-optimization. Incorporating DER co-optimization results in 85,000 GW-mi of new transmission builds, compared with 75,000 GW-mi without DER co-optimization. The study notes that the model does not simply replace transmission with DER, but rather removes transmission that is no longer economical and builds transmission in areas where it is more economical and supports grid decarbonization.

Investments in the distribution system are also crucial. Co-optimizing distribution system improvements with utility-scale generation contributes to significant reductions in distribution system costs. Co-optimizing the expansion of the distribution grid and development of DERs reduces total resource costs—mostly distribution system costs—by $109 billion by 2030 and by

[47] While each study referenced here may have slightly different definitions, a *distributed energy resource* is defined here as any electricity generation resource connected to distribution system facilities with a nominal rating of less than 100 kV.

$515 billion by 2050 nationwide, compared with a scenario that considers only utility-scale solar generation (Clack et al. 2021).

Clack et al. (2021) process a scenario with utility-scale and distribution system co-optimization in which DERs can grow to meet net-zero emissions in the U.S. economy by 2050. They find that all states except Montana and Oregon significantly increase interstate transmission capacity. The largest new transmission buildout is in the northeastern United States, whereas the Western Interconnection has lower buildout. Although transmission buildouts are still required, Ardani et al. (2021) demonstrate that because DERs can provide the same services as utility-scale solar generation, they offset the need for generation and transmission resources to maintain resource adequacy.

Hawaiian Electric (2023a) finds that alternative transmission solutions, including DERs, can cost effectively manage the buildout of new transmission required to meet clean energy targets on Hawaii island, Oahu, Maui, Lanai, and Molokai. Forecasted deployment of DERs, however, will require an increase in hosting capacity in some areas, particularly in the longer term. The study also finds the need to address system stability risks created by increased DER integration, such as momentary cessation.

## Grid-enhancing technologies can improve the operational efficiency of existing transmission systems

GETs include a suite of solutions capable of managing transmission congestion and increasing line utilization rates by expanding existing transmission system capacity and improving operational efficiencies. GETs generally fall under software and hardware-based solution categories, which can be deployed to improve transmission system operations (DOE 2020b). Software solutions generally serve to enhance control and protection systems, advanced optical sensing and metering tools, real-time contingency analysis tools, and artificial intelligence-assisted operator decision-making processes. Hardware solutions typically serve to improve physical assets and the infrastructure responsible for carrying, converting, or controlling electricity.

GETs include dynamic line ratings (DLRs), power flow controllers (PFCs), dynamic transformer ratings, and topology optimization, among others (DOE 2022b).[48] Beyond congestion relief and increasing line utilization rates, GETs provide several system benefits, including situational awareness to enable safer real-time operations, asset deferral while longer-term solutions are implemented, increased grid resilience, and asset health monitoring (DOE 2022b).

GETs deployment can improve the reliability of the existing transmission system and can do so more economically than traditional transmission expansion in certain scenarios because GETs deployment often involves lower capital costs compared with new transmission line construction (DOE 2022b). GETs deployment can also complement traditional transmission expansion by reducing or avoiding impacts due to outages required for new transmission upgrades and new transmission line interconnection (Tsuchida et al. 2023).

[48]Energy storage is also sometimes identified as a GET, although it is discussed separately in this Needs Study.

DLRs use sensing devices and algorithms to collect real-time weather data and/or other information on ambient conditions that affect the operation of a transmission line and calculate the ampacity[49] of a conductor more accurately. More accurate consideration of ambient conditions can enable operators to model the true thermal limits of the line more effectively at any given moment using near real-time conditions. Use of DLRs often yields greater capacity than using static line ratings, which do not account for real-time ambient conditions, and thus provides an opportunity to safely use the existing transmission system more efficiently (DOE 2022b). Potomac Economics (2021a) identifies concerns with the use of conservative static line ratings in the Midwest and Delta regions and estimates that the use of ambient-adjusted line ratings would generate significant benefits. As a result, Potomac Economics (2021a) recommends that MISO improve the flexibility of its systems and processes to enable the use of more dynamic and accurate line ratings.[50]

Like DLRs, dynamic transformer ratings monitor transformer operating temperature to more accurately determine power limitations based on thermal thresholds and can therefore unlock additional transmission capacity with greater accuracy of ratings (DOE 2022b). Transformers are typically rated using criteria that do not exceed a static current rating and a dynamic measure of transformer ratings. The criteria account for variables such as ambient temperature, amount of electrical current delivered to the transformer, age of the transformer, and type of cooling systems installed (DOE 2022b).

PFCs are a set of technologies that reroute power away from overloaded, congested lines onto underutilized, less congested lines in the transmission network. PFCs operate by adjusting physical properties of the line. Along with DLRs and other GETs, PFCs provide another important tool for optimizing the use of the current network (DOE 2022b). Topology optimization software serves a similar function as PFCs by identifying reconfigurations in the grid to route power flows around congested or overloaded transmission elements. Both PFCs and topology optimization software can more evenly distribute power flows across the transmission network, which can increase the capacity of the existing grid (DOE 2022b).

Both DLRs and PFCs are the focus of the 2022 DOE study: *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*. This study models the impact of GETs in New York under three generation scenarios: a scenario with the renewable generation currently in service in NYISO; a second scenario with 3 GW of additional solar generation capacity and 4 GW of additional wind generation capacity that was in the NYISO Interconnection Queue at the time of the study; and a third scenario with the required renewable generation to achieve 70% renewable generation by 2030. The report outlines customer benefits that could be realized by implementing DLRs and PFCs in these scenarios, including annual avoided curtailment savings ranging from $1.7 million from using DLRs to $9.1 million from using DLRs and PFCs, and adding a new substation. Although the study finds that more traditional upgrades, such as line reconductoring and adding a new substation, could yield the highest savings in avoided curtailment, these upgrades come with an added cost and take longer to deploy. GETs can yield high curtailment savings at a lower cost than traditional transmission solutions in some cases in the near term, and therefore

[49] The maximum amount of current that a wire can safely carry.
[50] Ambient-adjusted rating uses ambient air temperature to adjust line ratings over time.

can be a more efficient use of ratepayer funds (DOE 2022b). The study also outlines recommendations for the further deployment of GETs across different parts of the system.

## Advanced conductors and cables can increase transmission transfer capacity

The use of advanced conductors and cables in both new transmission infrastructure projects and existing infrastructure rebuilds and upgrades can significantly increase transmission transfer capacity compared with conventional conductors and cables. Advanced conductors generally refer to electrical conductors that utilize carbon and/or composite cores rather than steel cores typically used in conventional conductors.[51] Carbon and composite core characteristics allow for lower transmission line losses, up to two times the amount of carrying capacity compared with conventional conductors, lower weight, and low sag at higher temperatures, which can address transmission line thermal limitations (DOE 2020b). Recent types of advanced conductors include aluminum conductor composite reinforced, aluminum conductor composite core, and aluminum conductor carbon fiber reinforced conductors. DOE (2020b) also notes that high-temperature superconducting equipment, when used in transmission lines, is capable of transmitting power with little to no electrical losses at lower temperatures and can provide up to 10 times the maximum current-carrying capacity of conventional cables with the same cross-sectional area.

DOE (2020b) finds that advanced conductors and high-temperature superconducting equipment deployment can serve to increase transmission system transfer capacity and can be a particularly efficient and cost-effective method of increasing transmission capacity of the existing system when used to reconductor or replace existing transmission lines. Caspary and Schneider (2022), for example, find an estimated 200,000 miles of existing transmission lines will require replacement over the next decade across NERC regions. The report finds that advanced conductor deployment to address 25% of this aging infrastructure need could increase existing transmission capacity to facilitate up to 27 GW of generation capacity annually over the next decade. The report also finds that increasing transmission capacity by replacing aging transmission lines with advanced conductors would generate at least $140 billion in consumer energy savings over a 10-year period.

## Microgrids can bolster the resilience of the transmission system

Integrating microgrids into the grid improves the efficiency and effectiveness of the transmission system (DOE 2020b). Microgrids further serve as an effective platform for integrating DERs and reducing costs while bolstering the resilience of the Nation's electricity system. The value of microgrids has grown with FERC Order 2222, under which the DERs that are aggregated and optimized in microgrids can participate in wholesale energy markets and can realize more of their maximum potential benefits.

The full value of microgrids can be categorized into bulk system services (generation capacity, contingency reserves, etc.), transmission and distribution services (congestion relief, upgrade

[51] The most commonly deployed conventional overhead conductor is the Aluminum Conductor Steel Reinforced conductor.

deferral, etc.), and customer services (demand charge management, reliability, etc.). One utility has characterized 14 unique value streams in planning and using microgrids for benefits now and into the future (Lightner et al. 2020). As of mid-2019, 19 states and the District of Columbia had either adopted or were actively exploring adoption of performance-based ratemaking structures to incentivize utilities to use resources beyond traditional generation to meet capacity needs and achieve high rates of reliability (Wang and Crawford 2019), which microgrids could potentially provide.

With expanding deployments of DERs, microgrids play an increasingly important role as an alternative transmission solution to provide power to meet local loads while supporting grid performance objectives (e.g., reliability, resilience, ancillary services). By doing so, microgrids help defer or avoid the need to build new power lines and can allow communities to have greater control over energy resources. DOE envisions microgrids as building blocks of the future grid that will accelerate the transformation toward more distributed and flexible architecture in a socially equitable and secure manner (DOE 2021).

In Hawaii, Hawaiian Electric is currently working with the National Renewable Energy Laboratory and the Hawaii Natural Energy Institute to identify opportunities for the development of microgrids across Oahu to improve electrical infrastructure resilience (Hawaiian Electric 2023a).

# V.e. Siting and Land Use Considerations

## Siting transmission can be a major challenge

Multiple studies specify siting of high-voltage lines as a major challenge to transmission expansion, indicating that developers often must navigate multiple state processes and local and federal government requirements. As detailed in FERC (2020), developers are often required to navigate multiple state processes as well as federal and local requirements. To obtain a Certificate of Public Convenience and Necessity,[52] developers of multistate projects must demonstrate that their project is in the public interest in each state. Criteria used to make determinations may differ in each state and may even be inconsistent. For example, some states may focus on intrastate benefits and costs only, while others may also take into account or even require interstate, regional, or national benefits and costs. Further, some states may require broad environmental and economic benefits and costs, while others may consider specific policy goals. The Department funds the Regulatory and Permitting Information Desktop (RAPID) toolkit as a resource to catalog these many differences (*see* accompanying text box).

[52] Certificates of Public Convenience and Necessity go by different names in each state but are generally granted by state public service commissions to indicate than an infrastructure project is deemed in the public interest and therefore is entitled to specific rights, such as eminent domain or rate-basing costs among all customers.

**DOE Work on Transmission Permitting**

The Department funds the Regulatory and Permitting Information Desktop (RAPID) Toolkit, which provides information about federal, state, and local permitting and regulations for utility-scale renewable energy and transmission projects. Developed and maintained by the National Renewable Energy Laboratory, the toolkit makes permitting information easily accessible from a single site by providing links to permit applications, processes, manuals, and other related resources.

National Renewable Energy Laboratory, The RAPID Toolkit: Facilitating Utility-Scale Renewable Energy Development, https://www.nrel.gov/state-local-tribal/blog/posts/the-rapid-toolkit-facilitating-utility-scale-renewable-energy-development.html.

As stated in Xu et al. (2021), differences in planning and permitting processes of the state and local authorities along the path of a transmission line makes siting transmission a major hurdle. FERC (2020) and Xu et al. (2021) further indicate that obtaining approvals in each state also may be difficult because many states focus on intrastate burdens and benefits. For example, a transmission line that does not directly connect resources within a state might not receive permits required to traverse the state.

Additionally, developers face hurdles during the planning process, wherein differing drivers of transmission needs or siloed consideration of the multiple benefits of transmission may exclude valuable projects or complicate their path to construction. Conflicts also arise over cost allocation, as quantifying and determining who receives the benefits is especially challenging. FERC (2020) adds that the planning and permitting process might further complicate transmission development because in addition to state laws, the project may also be subject to local and federal review. For example, local review may be required for authorizations such as zoning permits and high-voltage transmission lines that cross federal lands may require permits from federal agencies that have different information needs and decision criteria. Overall, NERC (2021) describes high-voltage transmission expansion as time consuming and often involving significant siting challenges.

## Co-location of transmission corridors is possible in some cases

Several studies (FERC 2020; Xu et al. 2021; Blaug and Nichols 2023; NGI Consulting et al. 2022) suggest co-locating transmission in transportation corridors could help mitigate some siting and land acquisition issues. Use of existing rights-of-way can limit the amount of greenfield development, keeping new development in areas that have already been disturbed (Blaug and Nichols 2023). Co-location of transmission along highways specifically has the added benefit of enabling electric vehicle charging stations, which will be necessary in high electrification scenarios (NGI Consulting et al. 2023). Several states have moved forward with co-location strategies for transmission lines (FERC 2020; NGI Consulting et al. 2022).

Co-locating transmission lines within existing rights-of-way may be feasible if linear infrastructure corridors near the route of a proposed transmission line exist and contain excess

space. Rights-of-way refer to the land surrounding infrastructure equipment that is required for operation (NERC 2022b) and must be kept free of excess vegetation and the built environment that may negatively impact operations. High-voltage transmission lines require a corridor that can be as wide as 65 meters to accommodate the construction and placement of multiple cables (National Grid 2017; PSCW 2011). The right-of-way that must be retained for operation and maintenance can be narrower than that needed during construction.

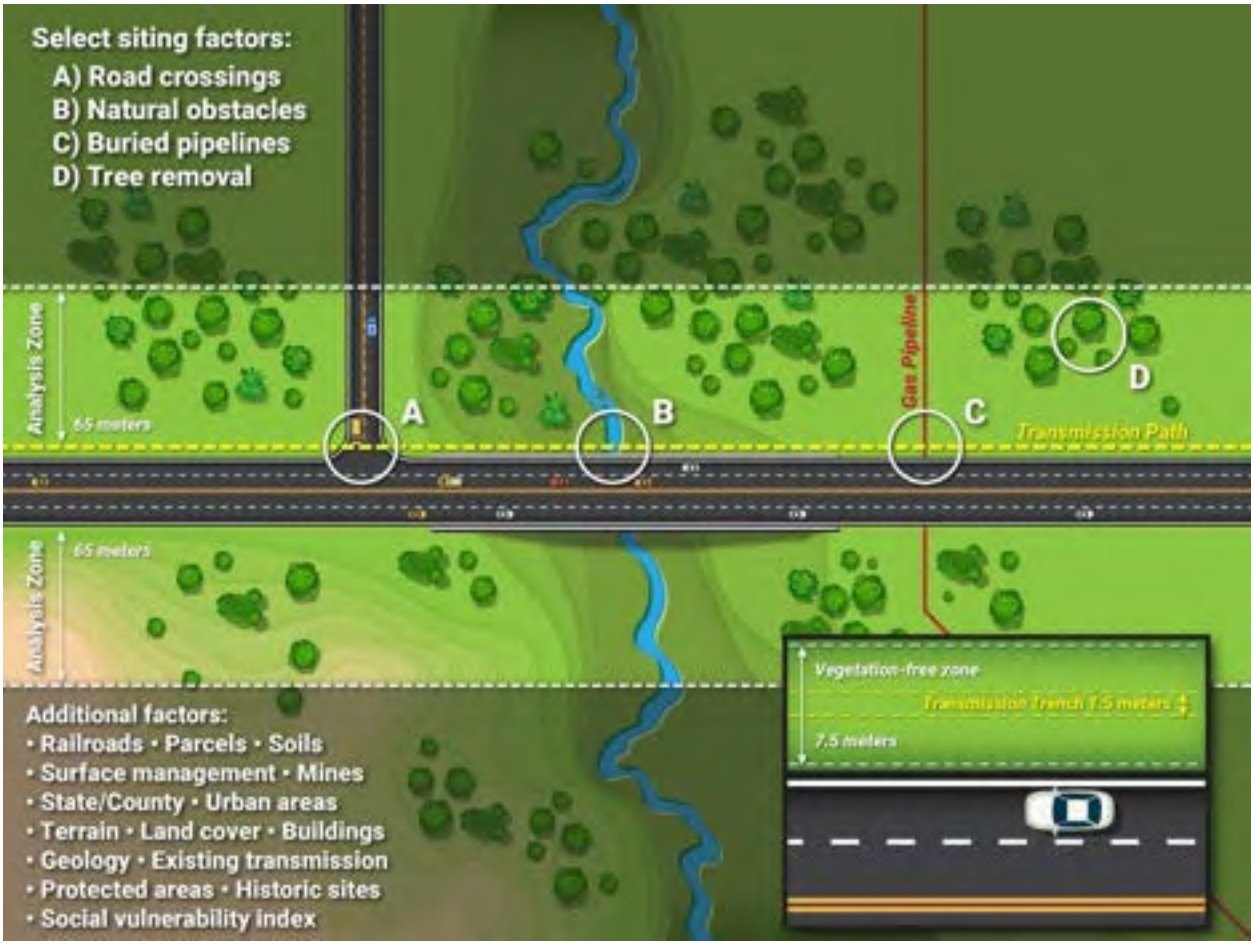
In 2022, researchers at the National Renewable Energy Laboratory (NREL) assessed the feasibility of siting undergrounded transmission lines along highways. This analysis relied on readily available datasets to develop a methodology for assessing highway rights-of-way and did not include any fieldwork that would help to further validate the assessment. High-level outcomes and detailed methods of the NREL effort are documented here and in the Supplemental Material, respectively. The assessment provides a detailed quantification of siting criteria that may impact the development of underground electric transmission lines along the contiguous U.S. interstate system. The analysis focuses on areas within the rural and rural-urban interfaces but does not assess criteria for large cities within metropolitan statistical areas. Specific routes assessed can be found in Figure V-9.

*Source: Produced by National Renewable Energy Laboratory. Data from U.S. Department of Homeland Security Geospatial Management Office (GMO 2022)*

***Figure V-9. Highway right-of-way routes assessed by National Renewable Energy Laboratory. Routes are partitioned by dominant direction.***

The analysis uses high-resolution spatial datasets that capture many siting considerations—such as land use conflicts, vegetation cover, terrain, sensitive wildlife habitats, soil composition, and infrastructure intersections—to characterize each acre of land extending 65 meters on either side of major highways. The analysis uses this 65-meter swathe as a conservative estimate of construction width required if several lines were installed (National Grid 2017) and is considered a temporary disturbance of the landscape. In practice, a much smaller, roughly 7.5-meter, permanent right-of-way would be required for each buried transmission line. Figure V-10 presents a conceptual graphic of the analysis conducted for each highway right-of-way.

The NREL analysis provides a first national-scale assessment of relevant siting criteria for direct burial transmission along highway corridors. While the analysis provides unique insights for siting, it does not attempt to evaluate tradeoffs between routes—whether those tradeoffs are economic, social, or technical in nature—and does not select optimal routes. Several high-level outcomes of the analysis are presented next.

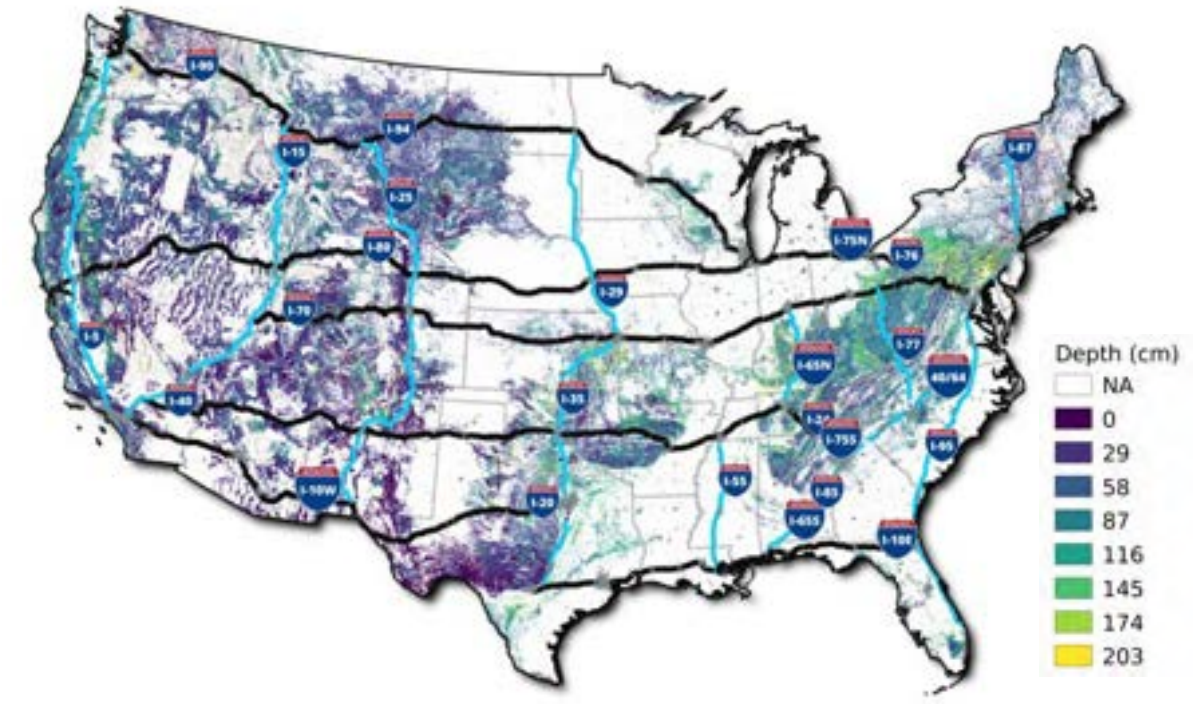



*Source: Produced by National Renewable Energy Laboratory.*

***Figure V-10. Conceptual graphic of the National Renewable Energy Laboratory right-of-way spatial analysis.***

It can be costly to site underground transmission along rugged terrain or shallow bedrock depth. Depth to bedrock data provides insight on where undergrounding transmission lines may not be economically feasible. While mountainous areas have both highly rugged terrain and shallow bedrock depth, even relatively flat regions of the country can also have shallow bedrock. Figure V-11 shows the minimum depth to bedrock within the contiguous United States. Highways in the Mountain and Southwest regions have particularly shallow bedrock, as do portions of Texas, the Southeast, the Mid-Atlantic, and New York.

Care must be taken when designing a power line that crosses other infrastructure, such as gas pipelines or roads, to be sure that all can operate safely and without interference. Co-located transmission lines that intersect other infrastructure corridors may require advanced installation techniques, further increasing installation costs. In general, the number of intersections that a highway crosses increases as the route nears major urban centers regardless of where it is located, as shown in Figure V-12. Sections of highway in the Delta (I-10, I-40, I-55), Florida (I-10), Southeast (I-24, I-85), and Midwest (I-39, I-75, I-90, I-94) regions have the lowest number of intersections with other infrastructure.




*Source: Produced by National Renewable Energy Laboratory. Data from Natural Resources Conservation Service (NRCS 2019), Geospatial Management Office (GMO 2022).*

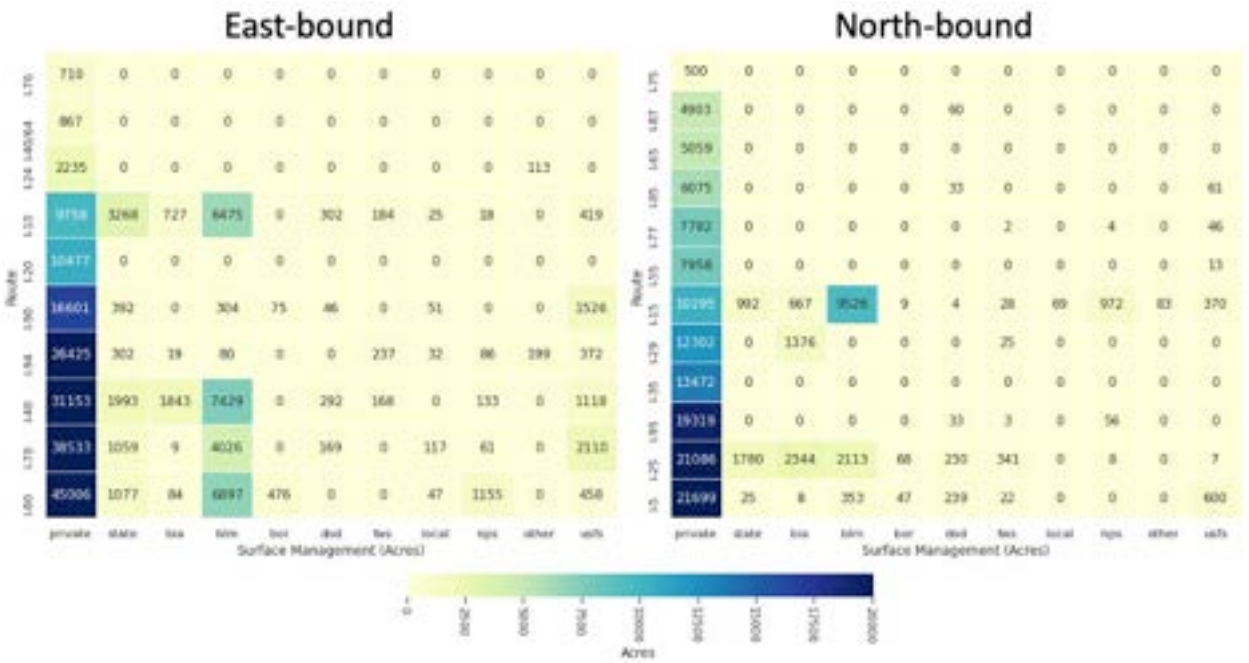
***Figure V-11. Minimum depth to bedrock along major highway corridors.***

*Source: Produced by National Renewable Energy Laboratory. Data from Geospatial Management Office (GMO 2022).*

***Figure V-12. Highway segments and the count of intersections with other roads, natural gas pipelines, and railroads.***

The land alongside interstates is predominantly owned or managed by private entities. Private owners have varied interest in leasing their land to transmission developers, and finding several consecutive owners willing to lease their land for transmission development along a single route can be difficult. Siting along federally managed lands reduces the number of landowners a developer must work with to procure rights-of-way (FERC 2020) but requires a National Environmental Policy Act (NEPA) review to develop. Only a few interstates—notably those east/west routes in the Mountain and Southwest regions (I-10, I-40, I-70, I-80, I-15)—contain significant tracts of state or federally managed lands, as seen in Figure V-13.

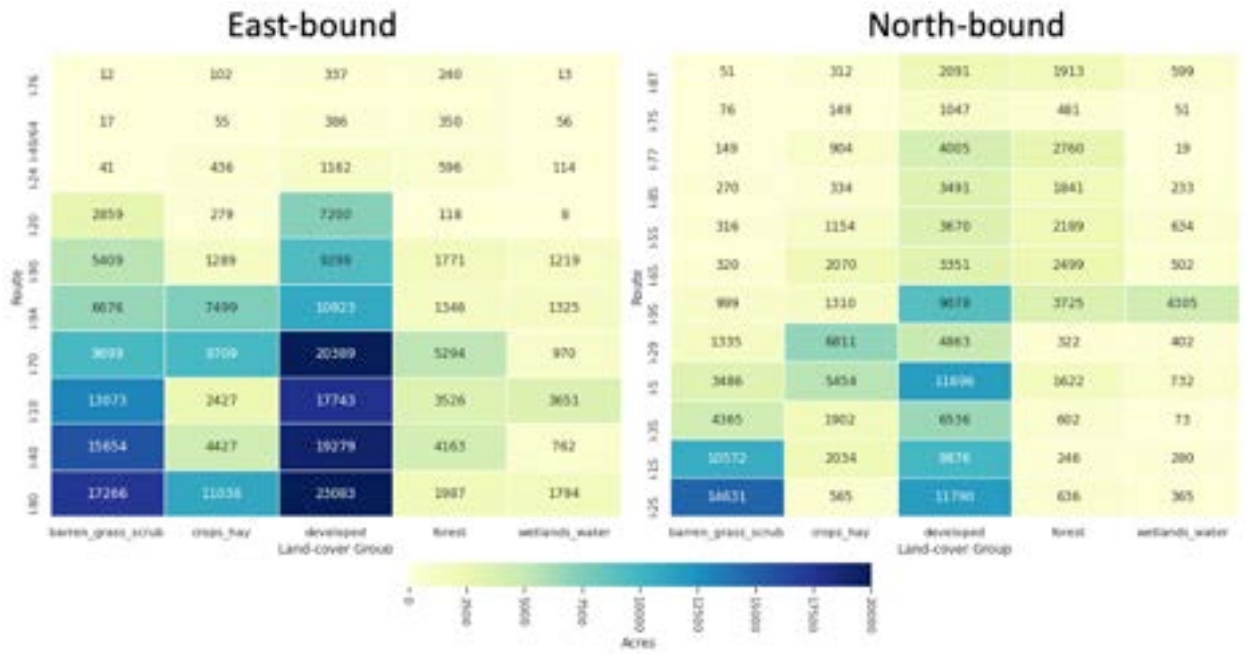
In addition to being predominantly privately owned, the majority of land abutting each interstate is considered "developed," to varying densities of development. Aside from developed land, there are also significant amounts of barren grassland, forests, crops, and wetland along some interstates. Siting transmission is easiest along continuous tracts of open land that limit environmental degradation. Figure V-14 shows the number of acres within each land use/cover grouping by highway route.




*Source: Produced by National Renewable Energy Laboratory. Data from Environmental Systems Research Institute, Inc. (ESRI 2018).*

*Note: Acronyms in the x-axes of these charts refer to Bureau of Indian Affairs ("bia"), Bureau of Land Management ("blm"), Bureau of Reclamation ("bor"), Department of Defense ("dod"), Fish and Wildlife ("fws"), National Parks Service ("nps"), and U.S. Forest Service ("usfs").*

***Figure V-13. Surface management acres within highway right-of-way by route.***




*Source: Produced by National Renewable Energy Laboratory. Data from Earth Resources Observation and Science (EROS 2016).*

***Figure V-14. Land use/cover acres within each highway right-of-way route.***

In areas with high levels of existing infrastructure development, transmission siting efforts should account for the cumulative impacts to public health, the environment, cultural resources, or existing social burdens that new transmission infrastructure may magnify (Federal Interagency Working Group on Environmental Justice and NEPA Committee 2016). The NREL analysis highlights that expanding many highway rights-of-way to accommodate transmission could impact already vulnerable communities by considering the Centers for Disease Control Social Vulnerability social vulnerability index (ATSDR 2023) along each highway route. Highways in the Florida, Southeast, Delta, Texas, Southwest, and California regions run through communities with high social vulnerability indices. Sections of highway with the lowest social vulnerability indices are found in the Midwest, Plains, and Mountain regions. The social vulnerability index of communities along all major interstates are shown in Figure V-15.

FERC (2020) and NGI Consulting et al. (2022) identify several regulatory and economic barriers to such co-location. Some state laws prohibit or in other ways restrict the co-location of transmission in highway rights-of-way. Co-location may also increase costs if the highway does not run in the direction compatible with the project. Further, electrical interference can affect the protection systems of oil and gas pipelines and accelerate corrosion, and the induced currents from high-voltage lines can also affect railroad signaling systems. These issues could limit co-location of transmission in pipeline or railroad rights-of-ways.

*Source: Produced by National Renewable Energy Laboratory. Data from Agency for Toxic Substances and Disease Registry (ATSDR 2023)*

***Figure V-15. Highway right-of-way segments characterized by Centers for Disease Control Social Vulnerability Index.***

Overhead lines are exposed to air, which serves to insulate the electrical conductors and to cool them. Underground lines often use a gas or fluid oil substrate for cooling within several layers of insulating material (PSCW 2011). The time required to locate and repair a fluid oil leak or electrical fault of an undergrounded transmission line can be more than 25 times as long for an overhead transmission line (National Grid 2017). Both construction and repair costs are higher for undergrounded transmission lines than overhead lines in general (PSCW 2011; National Grid 2017), but the design specifics of any individual project and desirable characteristics of undergrounded transmission lines may offset those concerns. Additional safety and security concerns arise when facilities are co-located; incidents related to one facility can affect the co-located facility due to the physical proximity.

Finally, the volume of soil that must be excavated for undergrounded cables is over 14 times that required for an equivalent overhead line, which only requires relatively shallow excavation for the tower structures intermittent along the length of the line (National Grid 2017). Given the volume of soil disturbed, trenching through farmlands, forests, wetlands, and other natural conservation areas can cause significant land disturbances (PSCW 2011). This is particularly important when designing transmission lines through ecologically sensitive areas.

Given these challenges, overhead power lines have electrical and environmental advantages that could result in fewer siting restrictions than undergrounded cables and could be more feasible to co-locate in some cases.

## Transmission siting must balance competing land use interests

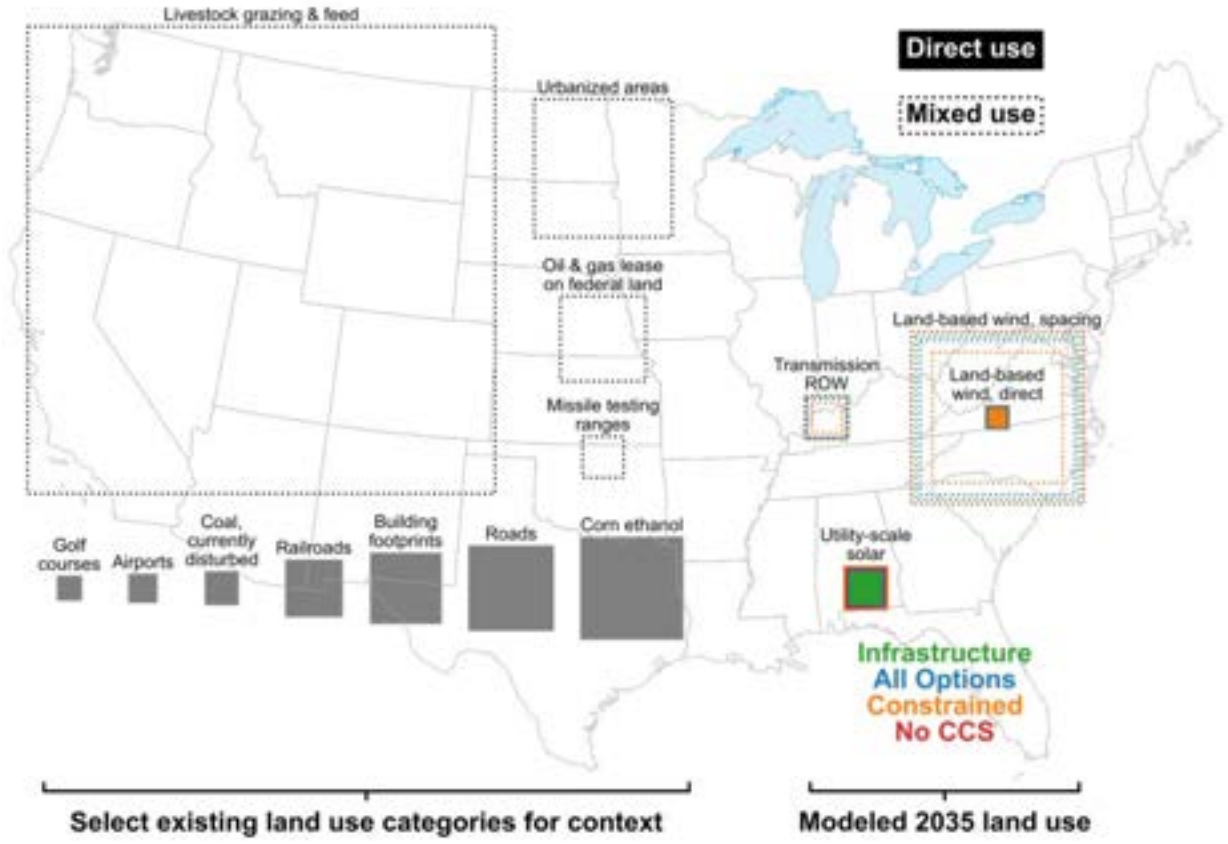
Land acquisition is described as a challenge in transmission development in Ardani et al. (2021). While the United States has large land area, there are often competing interests in the best use of those lands, including energy infrastructure development. Several land-intense energy, industrial, agricultural, and recreational activities are compared in Figure V-16.

Capacity expansion models, like those used in Section VI, try to capture this challenge by significantly increasing the input cost assumptions of transmission development. In their modeling, Cole et al. (2021) increase transmission costs by a factor of five in some scenarios to capture the challenges of siting new lines. These increased costs are meant, in part, to capture the capital cost increases of undergrounding significant portions of transmission lines.

**DOE Work on Transmission Siting**

The Department is proposing to amend its regulations for implementing Section 216(h) of the Federal Power Act and proposing to establish the Coordinated Interagency Transmission Authorization and Permits (CITAP) Program, a collaborative process between federal agencies and project proponents to ensure the timely review and decision making for federal authorizations consistent with the nation's environmental laws, including laws that protect endangered and threatened species, critical habitats, and historic properties. The Department's Transmission Siting and Economic Development (TSED) Program, authorized by IRA Section 50152, is designed to build an equitable clean energy economy by accelerating and strengthening Tribal, state, and local transmission siting and permitting processes while promoting economic growth in communities impacted by major new or upgraded transmission lines.

Denholm et al. (2022a) consider land use associated with long-distance transmission rights-of-way under modeling scenarios that achieve a contiguous U.S.-wide 100% clean electricity system by 2035. Transmission can share much of its rights-of-way with other activities, such as agricultural fields or recreational paths, and are considered a "mixed use" activity. This contrasts with other "direct-use" activities, for which the land is solely utilized for the single activity. The primary scenarios in Denholm et al. (2022) result in land use footprint areas for transmission rights-of-way between 13,000 and 28,000 $km^2$. Figure V-16 illustrates total area occupied by long-distance transmission rights-of-way resulting from the study compared with other common land use activities. The transmission (mixed use) land area resulting from the 100% clean electricity system by 2035 scenarios are roughly equivalent to the footprint of missile testing ranges (mixed use), utility-scale solar (direct use), and currently disturbed coal lands (direct use). The resulting long-distance transmission right-of-way is less than the direct-use land currently used by railroads within the contiguous United States.




*Source: National Renewable Energy Laboratory (Denholm et al. 2022a).*

***Figure V-16. Total area occupied by long-distance transmission rights-of-way compared with other land use activities.***

Alaska and the Hawaiian Islands face unique challenges due to their land characteristics and population disbursement. EPA (2020) notes that in Alaska, the remote nature of much of the state, lack of roads, and high financing costs associated with transmission buildout are significant barriers to transmission development. Allen et al. (2016) describes the challenges associated with interconnecting isolated electric grids in rural Alaska due to the small size and geographic remoteness of many rural microgrids as well as harsh weather and terrain, which often make building and maintaining transmission between rural villages impractical. The report also finds that Alaska's utilities rely heavily on state and federal grants to upgrade and maintain systems. While larger communities and cooperatives may be able to access capital more readily through federal agencies or financial assistance through local financial institutions, smaller rural utilities often have fewer options (e.g., limited to fuel loans from the state or fuel dealers), creating economic limitations, which can lead to underinvestment in infrastructure.

Land use challenges in Hawaii can also create barriers to transmission development. In Kaua'i, for example, transmission development activities must consider the potential impacts to habitats for endangered or threatened species, including seabirds, waterbirds, and the green sea turtle. Conservation measures to mitigate impacts due to transmission development can

include powerline reconfiguration, static wire removal, and increased transmission line visibility with reflective or LED lighting to minimize collision on high-risk line segments (KIUC 2023b).

## Community, stakeholder, and Tribal engagement is imperative

Electric transmission infrastructure projects have the potential to extend through public, private, and Tribal lands, as well as across multiple state and local government jurisdictions. Meaningful engagement with landowners, communities, stakeholders, and Tribes impacted by new or upgraded transmission project development early in the project is critical to ensure the alignment and support among a broad range of interests and to facilitate successful project completion. Transmission infrastructure can serve to bring location-constrained clean energy generation to load centers and accommodate the retirement of existing fosssil fuel-fired generators, often cited within communities with high energy burdens. Meaningful engagement practices can create a platform for discussion surrounding carbon emission reductions benefits while leading to more equitable siting decision-making.

Blaug and Nichols (2023) describe the conflicting interests between transmission developers and landowners and communities that can often lead to project opposition. In particular, the authors note landowner concerns can typically arise due to potential project impacts on property value, land aesthetic, and/or the surrounding environment, or due to questions regarding potential health impacts or lack of localized benefits. Traditional project development dynamics are typically at the root of many of these concerns, which include the developer's right to exercise eminent domain, as well as the historical procedures of landowner and community engagement only after key routing decisions have been made, leaving complex regulatory approval processes the main avenue for stakeholder participation.

Blaug and Nichols (2023) note the importance for developers to engage early and often in the development process as well as throughout the life of the transmission project to ensure landowners and communities are kept up to date and extended platforms for engagement that demand fewer resources and time compared with many regulatory approval processes. Similarly, Ung-Kono (2023) recommends frequent and sustained community engagement in the transmission development process, particularly in the form of in-person meetings within the communities potentially impacted by the project. In-person community meetings held early in the planning process can serve to build trust and create a collaborative environment where information can be exchanged freely beyond information provided traditionally through existing regulatory approval processes.

Transmission siting and land use activities also intersect with key energy justice issues. Ardani et al. (2021) suggest that community engagement is key to addressing siting concerns and making equitable siting decisions. Ardani et al. (2021) add that transmission infrastructure can raise local opposition because of perceived or real negative impacts on property and the environment. The authors emphasize that increased community engagement is crucial for addressing local concerns and making equitable siting decisions, as historically, marginalized communities have had a disproportionate share of the cost and burdens of transmission network expansion.

In the beginning stages of the transmission siting process, project sponsors may also consider utilizing tools such as EJScreen, EPA's environmental justice mapping and screening tool, the U.S. Census American Community Survey Data, and other environmental justice screening tools developed by various states to identify environmental justice communities and the potential impacts a transmission project may have on communities (Blaug and Nichols 2023). The authors note the importance of identifying key environmental justice communities and conducting outreach early in the development process to determine community needs and how to reduce potential impacts. For infrastructure related to transmission lines, which historically has prioritized placement in low-cost lands, high cumulative burden should be an indicator to avoid those areas. The Department has created a suite of tools to identify areas with increased vulnerability (*see* accompanying text box).

**DOE Work on Energy Justice**

The Council on Environmental Quality has developed the Climate and Economic Justice Screening Tool, an interactive map indicating community burdens in eight categories: climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development. The tool uses this information to identify disadvantaged communities that are experiencing these burdens.

Additionally, the Department has developed an Energy Justice Dashboard (BETA), which displays DOE-specific investments across the country overlaid on the several indicators of community burden described above. DOE is working to better understand how the Department's funding and investments are distributed to overburdened and underserved communities that have been left behind and unheard for too long.

Council on Environmental Quality, Climate and Economic Justice Screening Tool, https://screeningtool.geoplatform.gov/.

Dept. of Energy, Office of Economic Impact and Diversity, Energy Justice Dashboard (BETA), https://www.energy.gov/diversity/energy-justice-dashboard-beta.

Community benefits agreements created in partnership with environmental justice communities during engagement outreach can also be an effective tool in guaranteeing certain community benefits, such as local job creation and training, economic trust fund contributions or financial assistance, and unique revenue sharing or ownership configurations (Blaug and Nichols 2023; Ung-Kono 2023).

Federal agencies can also improve consideration of environmental justice issues as part of the NEPA review process for electric infrastructure projects. The Federal Interagency Working Group on Environmental Justice and NEPA Committee (2016) provide a set of recommendations for how federal agencies can improve engagement efforts while conducting environmental analyses for NEPA review. The report highlights the importance of early and meaningful engagement with potentially affected minority populations, low-income populations, and other populations that often have greater barriers to engagement during key stages of NEPA review. Specifically, the report recommends considering adaptive and innovative approaches to both

public outreach engagement during the following stages: defining the affected environment, identifying potentially affected minority and low-income populations, assessing potential impacts to minority and low-income populations, assessing potential alternatives, determining whether potential impacts to minority populations and low-income populations are disproportionately high and adverse, and developing mitigation and monitoring measures.

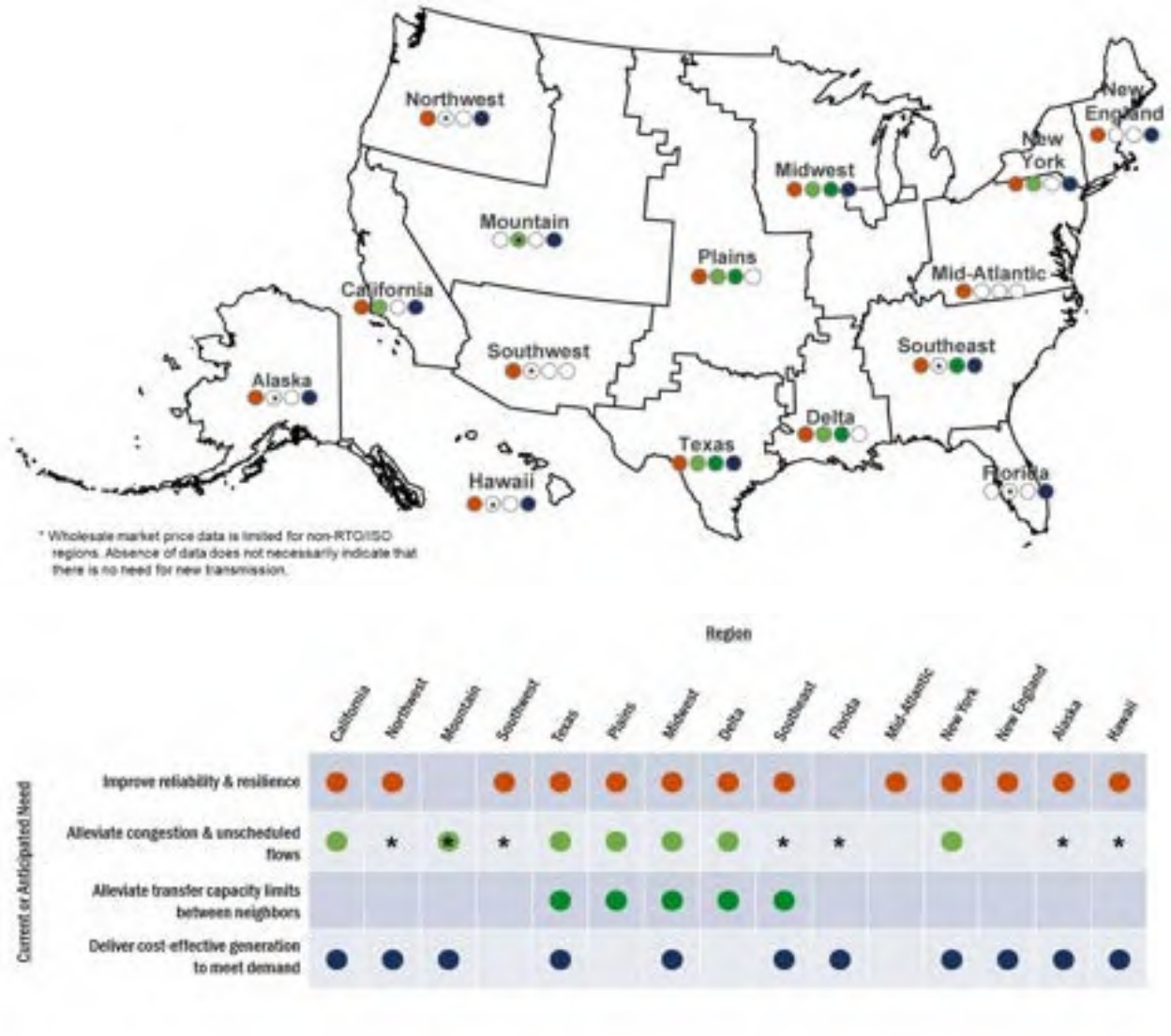
Additionally, the authors note that providing opportunities to discuss both process-specific information as well as the purpose and need of agency action early in the NEPA review process can help guide public input and efficient information collection to inform the decision-making process. Federal agencies may also consider information dissemination through electronic methods (e.g., virtual meetings, webinars, social media, and listservs) and in-person meetings to keep communities updated about procedural details. The report also notes the importance of maintaining relationships throughout the engagement process through a dedicated agency point-of-contact and the value of creating project-specific community advisory committees, or other established groups, which include representatives from potentially affected groups.

Blaug and Nichols (2023) also discuss the importance of project sponsor Tribal engagement. The authors note that while federally mandated Tribal consultation only involves interaction between the federal government and Tribal governments, transmission project sponsors may consider engaging with Tribes earlier in the development process before formal consultation processes begin. Tribal land and ownership of Tribal lands can be complex issues to navigate. For example, different categories of Tribal lands can include reservation land, treaty land, and lands containing cultural and historical Tribal resources, which may be owned by a Tribal government and/or individual Tribe's reservation lands and other homelands to which a Tribe has ongoing cultural and spiritual connections (Blaug and Nichols 2023). Early and meaningful Tribal engagement before key decisions have been finalized regarding project routing can allow for Tribal guidance for how best to avoid impacts to historic properties and culturally significant natural resources. Further, in addition to outreach to Tribal government leaders, developers would benefit to conduct outreach to Tribal communities as well as landowners, who may offer differing perspectives and interests.

## V.f. Conclusion and Summary of Transmission Needs and Benefits Identified Across the Reviewed Studies

The studies reviewed as part of this section discuss the key factors driving the current and anticipated need to expand the Nation's transmission system, including grid reliability, resilience, resource adequacy, generation mix and load profile changes, and congestion and curtailment issues. Study findings provide insight into how transmission capacity expansion through new and upgraded transmission infrastructure, as well as alternative transmission solutions, can address these transmission system needs, which are anticipated to increase as the power system continues to evolve. Indicators of system needs and the manner in which transmission can assist in meeting those needs are recurrent across the reports reviewed, which account for a wide range of study regions, modeling tools, and industry perspectives.

Figure V-17 summarizes findings of current and anticipated transmission needs by geographic region as determined by the data and studies referenced in the Section V literature review. The different color circles located on the map of Figure V-17 (top) correspond to the transmission needs listed in the dashboard (bottom).




*Source: See the Supplemental Material for supporting references and methodology.*

***Figure V-17. Summary of current and future transmission needs identified in Section V by geographic region.***

**System reliability and resilience remain key drivers in the need for transmission infrastructure in nearly every geographic region across the United States and are anticipated to drive transmission in the future.** Nationwide, transmission capacity expansion can serve to enhance system stability through improved operational flexibility, resource sharing, and frequency response. Reliability has been cited as the dominant driver for currently planned transmission projects.

**Transmission infrastructure will be particularly important in maintaining system reliability as an increasing amount of VER generation interconnects to the transmission system.** Various study findings highlight the need for transmission planning efforts to consider the unique electrical impacts of inverter-based resources, including the potential to cause low inertia, unstable voltage, low fault currents, or unpredictable behavior during grid disturbances. Despite these unique reliability concerns, transmission can accommodate increased VER generation integration in response to future changes in the generation mix while maintaining overall grid reliability.

**Transmission can also maintain reliability and bolster system resilience across the Nation in the face of extreme weather events that continue to increase in intensity and frequency**. The authors, including many regional planning entities and independent market monitors, identify transmission limitations and highlight transmission needs during recent extreme weather events, including heat waves in Texas, California, and the Northwest; Winter Storms Uri and Elliott; Hurricanes Laura and Ida; and cold weather events such as the 2018 “bomb cyclone” in New England, New York, and the Mid-Atlantic regions and 2019 “polar vortex” in the Midwest, among other events. Expanding transmission capacity between regions can improve the ability of the bulk power system to respond to such extreme weather events through operational flexibility and resource sharing.

**The need for additional interregional and cross-interconnection seams transmission capacity is particularly acute between the Plains, Midwest, Delta, Texas, and Southeast regions and their neighboring regions.** Interregional and cross-interconnection seams transmission capacity can also enable the system to take advantage of the geographic and temporal diversity of energy resources, which can improve the electric system’s ability to transport low-cost clean energy while bolstering system reliability through increased power pathways. A more interconnected grid has been found to also support resource adequacy, as new lines enable more flexible generation sharing, which can reduce the need for new generation in certain instances.

**Congestion is a major driver of new transmission infrastructure needs in the California, Northwest, Texas, Plains, Midwest, Delta, Mid-Atlantic, and New York regions, as well as in Alaska and Hawaii.** Transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion. This literature review provides an analysis of region-specific congestion using utility data and market monitor reporting. Load-weighted congestion costs are estimated to be the highest in CAISO and ERCOT. In New England, transmission investments have resulted in lower levels of congestion; however, an anticipated increase in offshore wind interconnection is expected to increase congestion in the southeastern subregion due to export constraints. In New York, congestion and constraints

have been found within New York between the upstate and Long Island areas. Significant congestion and constraints have been found to exist in the eastern and coastal parts of the Mid-Atlantic region, between the Midwest and Delta regions, and between eastern to western Texas. The changing generation mix has also introduced congestion in the Plains and in the Western Interconnect. The Plains region, for example, has experienced higher levels of congestion due to increased wind generation output. Alaska's transmission system has limited transmission transfer capacity between generation and major load centers, and certain transmission systems on the Hawaiian Islands, including Kaua'i, require additional transmission capacity. Similarly, the Northwest, Southeast, and New England have also been found to need additional transmission capacity to deliver more cost-effective generation to meet demand.

**Recent and anticipated changes in generation mix and load profiles present key drivers for new transmission**. Transmission infrastructure at the national level can help accommodate a diverse mix of new, clean VERs. New transmission infrastructure is required to transfer new renewable energy generation from remote or distant areas to load centers as the power system transitions to a decarbonized future. Additionally, various regional planning authority, utility, and state-level planning efforts in the California (and the Western Interconnection at large), Texas, Midwest, Mountain, New York, New England, and Southeast regions note the need to efficiently plan transmission to access location-constrained clean energy resources. As part of the anticipated increase in clean energy integration, transmission expansion can also help to reduce generation curtailment. Further, there is an even greater need for increased transmission buildout as decarbonization efforts may lead to increases in electricity demand due to high levels of end-use electrification. Planning efforts must account for potential reliability risks from increased load growth from electrification impacts.

**Alternative transmission solutions can complement new traditional transmission infrastructure, but do not obviate the need for additional infrastructure altogether.** Energy storage can serve as a crucial grid asset capable of supporting VER integration by shifting load across hours or days, smoothing seasonal peaks, and providing additional grid services. Hybrid variable renewable energy-plus-storage plants, for example, can also reduce the need for additional transmission when sited near load centers. Similarly, DERs can assist in meeting clean energy targets while lowering electricity costs for consumers. Other solutions, such as GETs and advanced conductors and cables, can help manage transmission congestion and increase transmission line utilization rates by expanding existing transmission system capacity. GETS have the potential to complement traditional transmission expansion by reducing impacts due to outages required for new transmission upgrades and new transmission line interconnection. Similarly, microgrids can present a myriad of transmission benefits, including the ability to provide generation to local load while providing significant reliability, resilience, and ancillary services benefits.

**Siting and permitting of new transmission infrastructure, including offshore wind transmission, remain a major challenge to transmission expansion due to disparate state and local siting and permitting processes and varied determinations of project benefits and cost allocation.** Land use and land acquisition also present challenges in the transmission development process. In geographic regions such as Hawaii and Alaska, for example, harsh terrain, population disbursement, and environmental concerns also present challenges to

transmission siting and development. In certain instances, it may be feasible to co-locate transmission infrastructure within existing transportation corridors to ease siting and land acquisition. However, there remain potential regulatory, economic, or logistical barriers to siting overhead or underground transmission within existing transportation corridors.

**Meaningful engagement with landowners, communities, stakeholders, and Tribes early in the transmission development process is key in ensuring equitable transmission solutions that mitigate potential impacts to communities.** Project sponsor and federal agency engagement is not only critical to ensure alignment among a broad range of interests, but it is also critical to ensure transmission development processes result in equitable siting decisions that mitigate potential impacts to disadvantaged communities and reduce cumulative energy burdens.

**Preliminary results from a Department-led survey directed by the Fiscal Year 2021 Consolidated Appropriations Act suggest that over 54,000 American Indian and Alaska Natives do not have access to electricity today.** Approximately 92% of AI/AN respondents reported regular electricity outages, often because of inadequate infrastructure or because they are serviced by a single power line lacking redundancy. Many Tribal lands have an abundance of renewable energy resources, and renewable generation development may provide opportunities for diversification, energy independence, environmental sustainability, and new revenue streams for AI/AK communities. Access to the transmission system would be required to generate such value for Indian Tribes and to bring economically viable generation resources to market.

# VI. Anticipated Future Need Assessment through Capacity Expansion Modeling

The U.S. power supply is undergoing a rapid transformation, reflecting evolving market conditions, geopolitical conflicts, and the increasing penetration of new generation and transmission technologies. Given the long development time for high-voltage power lines, the Nation's transmission needs should be defined as much by anticipated future need as current need. Congress has also directed the Department to consider expected future transmission congestion and constraints in this study.

Planning the future power system requires consideration of expected changes in supply and demand, including changing market conditions and consumer demand behavior. Capacity expansion modeling is a common tool used to estimate what the power demand and supply will be in future years. To accommodate many potential futures—for example, electrification of different quantities of end-use appliances and different adoption rates of advanced nuclear technologies—capacity expansion modelers consider multiple scenarios under a range of feasible assumptions.

Once future power system scenarios and input modeling assumptions have been established, capacity expansion models optimize for the lowest capital and operations costs, system wide, to identify the cost-optimal mix of generation, electric storage, and transmission investment. The models consider hourly energy dispatch constraints and some essential grid reliability services, such as resource adequacy.[53] The models optimize around all possible technology combinations and choose the least expensive solutions in each geographic zone given the range of assumptions and scenarios considered.

The capacity expansion modeling studies used here are national in scope and capture a wide range of likely future power sector characteristics. Given the rapid transformation of the power sector, there is value in considering how a diversity of supply and demand futures will impact the transmission system. Scenario-based transmission planning can capture large uncertainty in how supply and demand may change 20 or more years into the future. Capacity expansion modeling studies differ from typical industry-led transmission planning studies, which generally respond to regional, near-term transmission needs by identifying specific transmission projects as solutions (Pfeifenberger et al. 2021), rather than co-optimizing both generation and transmission solutions nationwide to meet regional needs.

The Department analyzed the modeled transmission builds that result from several recent national laboratory and peer-reviewed academic capacity expansion modeling studies to estimate the amount and location of future transmission need. The studies collectively examine hundreds of scenarios, capturing a wide range of possible power system futures. The values presented here are zonal estimates of the amount and general geographic location of future transmission need.

[53] The energy and reserve services considered by each capacity expansion model can be found in the referenced model documentation.

The precise characteristics and nodal locations of specific transmission projects to accommodate supply and demand changes would be determined by additional engineering analysis performed by the transmission planners. Additionally, any portion of these transmission system additions may require associated distribution or transmission system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds. These downstream analyses are critical to the transmission planning process to ensure reliable operation of the grid but are out of scope for the analysis presented here. Because of their nearer-term focus, many industry-led transmission planning studies employ inputs that are naturally more certain about the characteristics of the future power system. Section V reviews the results of many of these studies. Given the mismatch in temporal and geographic modeling scope, the results of the reviewed industry-led transmission planning studies are not included in this analysis.

The Department is currently undertaking a National Transmission Planning Study to bridge the gap between national, long-term capacity expansion modeling studies and regional, nearer-term transmission planning studies (*see* accompanying text box). The National Transmission Planning Study is conducting downstream engineering analysis of candidate transmission projects identified through capacity expansion modeling.

**DOE Work on Transmission Planning**

The Department is conducting the National Transmission Planning Study to identify transmission solutions that will provide broad-scale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability.

Dept. of Energy, Grid Deployment Office, National Transmission Planning Study, https://www.energy.gov/gdo/national-transmission-planning-study.

This section describes future power system scenarios that six capacity expansion studies considered and the resulting amount of new transmission each study modeled. Section VI.a. provides a high-level overview of all model scenarios considered in this analysis and explains how the scenarios were categorized for presentation of results. Section VI.b. explains how alternative transmission solutions are considered by the study scenarios. Sections VI.c. and VI.d. present the resulting regional transmission needed to meet changes in electricity demand and other power sector constraints. Section VI.c. presents the regional transmission expansion results, followed by interregional transfer capacity expansion results in Section VI.d. The transmission expansion results shown here are model outputs that illustrate the amount of anticipated transmission investments needed to meet a large variety of power sector futures. Given the diversity of demand-side, generation, and transmission solutions to future power sector needs, ranges of results are shown. Section VI.e. compares current transmission utility plans with the range of anticipated transmission deployment need according to the capacity expansion modeling results. Conclusions are provided in Section VI.f.

# VI.a. Included Studies and Scenarios

The anticipated transmission results of 300 scenarios from six capacity expansion modeling studies published since 2020 were analyzed.[54] The scenarios represent different potential futures for the Nation's power sector, all of which result in different assumptions about future electricity demand and the resulting deployment of transmission. The first study was performed by researchers at the Massachusetts Institute of Technology (Brown and Botterud 2020); four were performed by researchers at the National Renewable Energy Laboratory (Ardani et al. 2021; Brinkman et al. 2021; Cole et al. 2021; Denholm et al. 2022a); and the last was performed by researchers at Princeton University (Larson et al. 2021)). These studies and the results from their core scenarios were reviewed in Section V. Table VI-1 summarizes the six studies discussed here at a high level; a more detailed summary of and the specific treatment of transmission in each study can be found in the Supplemental Material.

***Table VI-1. Summary of six reports used in this analysis.***

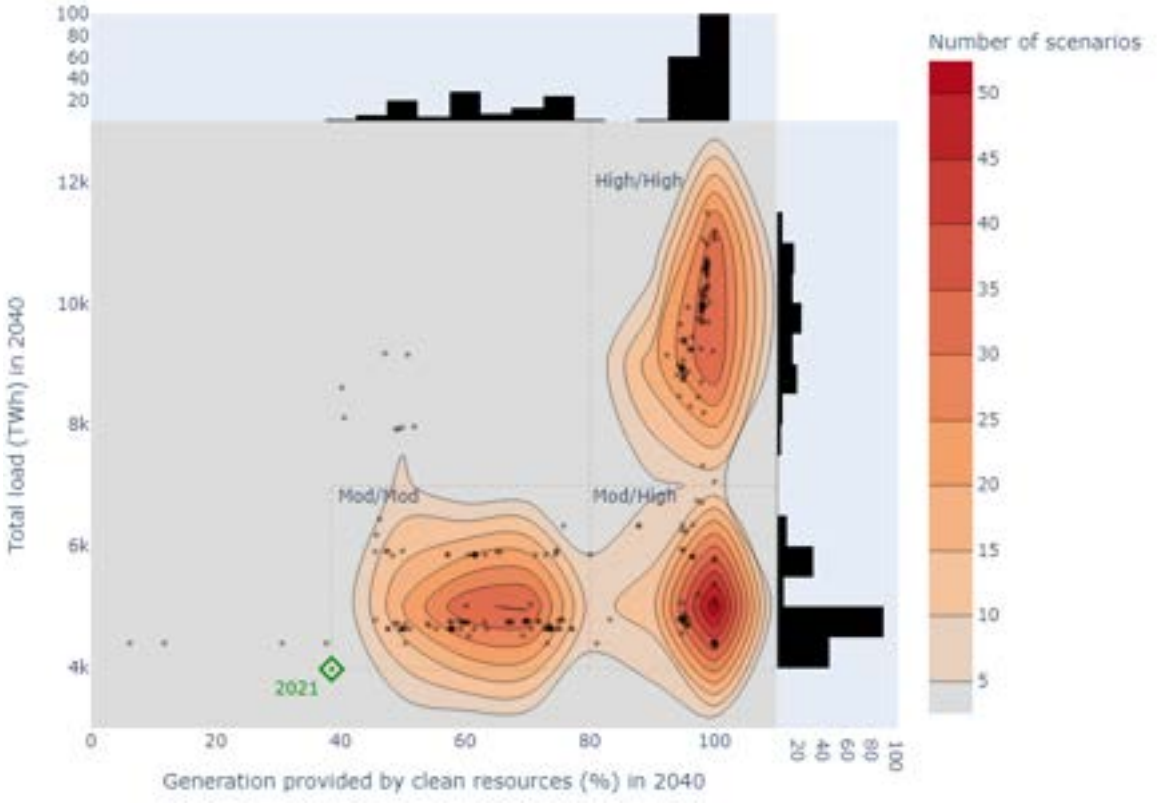
| Report | Driving Perspective | Temporal | Geographic | Included Modeling | Scenarios |
|---|---|---|---|---|---|
| Mass. Institute of Technology *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System*<br><br>Brown and Botterud (2020) | Considers costs associated with different transmission coordination and expansion cases, given 100% renewable energy system | Scope<br>2040<br><br>Resolution<br>CEM: single year modeled | Scope<br>Contiguous U.S.<br><br>Resolution<br>State | • CEM: custom co-optimized, linear capacity planning and dispatch model | Six core scenarios:<br>• No new transmission, no interstate coordination<br>• No new transmission, regional coordination (PA–AC)<br>• New state transmission, regional coordination (PA+AC)<br>• New state transmission, national coordination (USA–AC–DC)<br>• New regional transmission, national coordination (USA+AC–DC)<br>• New regional AC & DC transmission, national coordination (USA+AC+DC)<br>Plus 48 sensitivities |
| NREL *North American Renewable Integration Study*<br><br>Brinkman et al. (2021) | Considers impacts on power sector if transmission and generation planning conducted jointly with USA, Canada, and Mexico | Scope<br>2010–2050<br><br>Resolution<br>CEM: 2-yr<br>PCM: 5-min<br>RA: hourly | Scope<br>Continental<br><br>Resolution<br>Approx. nodal | • Capacity expansion modeling (ReEDS)<br>• Production Cost Modeling (PLEXOS)<br>• Resource Adequacy (PRAS) | Four core scenarios:<br>• Business-as-usual<br>• Low-cost variable generation<br>• Carbon constrained<br>• Electrification<br>Plus 38 sensitivities |

[54] Several other studies with anticipated future transmission expansion results reviewed in Section V were considered for inclusion in this analysis. Because of data issues (errors found in results, only preliminary results available at time of analysis, etc.), those studies were excluded.

| Report | Driving Perspective | Temporal | Geographic | Included Modeling | Scenarios |
|---|---|---|---|---|---|
| NREL *Standard Scenarios*<br><br>Cole et al. (2021) | Considers possible future power sector scenarios, given different technology costs and system conditions and adoption levels | Scope<br>2022–2050<br><br>Resolution<br>CEM: 2-yr<br>PCM: hourly | Scope<br>Contiguous U.S.<br><br>Resolution<br>Approx. BA | • Demand-side modeling (dGEn)<br>• Capacity expansion modeling (ReEDS)<br>• Production Cost Modeling (PLEXOS) | Three core scenarios:<br>• No New Policy<br>• 95% by 2050<br>• 95% by 2035<br>Plus 47 sensitivities |
| NREL *Solar Futures Study*<br><br>Ardani et al. (2021) | Considers role of solar energy, distributed energy, and electrification, given power sector decarbonization | Scope<br>2020–2050<br><br>Resolution<br>CEM: 2-yr<br>PCM: hourly<br>RA: hourly | Scope<br>Contiguous U.S.<br><br>Resolution<br>Approx. BA | • Capacity expansion modeling (ReEDS)<br>• Production Cost Modeling (PLEXOS)<br>• Resource Adequacy (PRAS) | Three core scenarios:<br>• Reference<br>• Decarbonization<br>• Decarbonization + Electrification<br>Plus 6 sensitivities |
| Princeton University *Net Zero America*<br><br>Larson et al. (2021) | Economy-wide net-zero emissions by 2050; implications for land use, capital mobilization, jobs, air pollution assessed for different net-zero energy system pathways | Scope<br>2020–2050<br><br>Resolution<br>CEM: 5-yr | Scope<br>Contiguous U.S.<br><br>Resolution<br>State (transmission outputs) | • Demand-side modeling (EP)<br>• Capacity expansion modeling for power and fuels sectors (RIO) | Six core scenarios:<br>• Reference<br>• High electrification (E+)<br>• Less high electrification (E−)<br>• Less high electrification, high biomass (E−B+)<br>• High electrification, less high variable energy resources (E+RE−)<br>• High electrification, 100% renewable energy by 2050 (E+RE+) |
| NREL *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*<br><br>Denholm et al. (2022a) | Considers different pathways to achieve 100% clean electricity by 2035 and net-zero emissions by 2050 | Scope<br>2020–2050<br><br>Resolution<br>CEM: 2-yr | Scope<br>Contiguous U.S.<br><br>Resolution<br>Approx. BA | • Demand-side modeling (dGEn)<br>• Capacity expansion modeling (ReEDS) | Four core scenarios:<br>• All options<br>• Infrastructure renaissance<br>• Constrained Siting<br>• No carbon capture and sequestration<br>Plus 122 sensitivities |

The amount of transmission expansion needed to meet future power sector scenarios depends heavily on the generation mix—notably the transition from thermal generators to high penetration of location-dependent clean energy resources—and future demand (Jenkins et al. 2022b). For this reason, the 300 capacity expansion scenarios are analyzed based on these two characteristics. The annual percentage of clean energy generation, including all solar energy technologies (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based and offshore wind power, hydropower, nuclear energy, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration technologies, and landfill gas plants were considered. Several transmission system operators are preparing for significant load growth in a variety of industries, including data centers and transportation electrification (Gledhill 2021; ERCOT 2021b; ISO-NE 2022a).

Figure VI-1 shows the combination of clean energy generation and electricity demand assumptions for all study scenarios in 2040. [55] The two outer histograms show the scenario counts with respect to clean energy penetration (x-axis) and total annual load (y-axis) individually. The center contour plot shows the scenario counts for both clean energy penetration and total load, considered together. A single point on the contour plot indicates the amount of clean energy and load assumed for a single scenario. Red shading contours indicate where many datapoints are clustered. The darker the shading, the more scenarios have that level of clean energy penetration and total load. The open diamond indicates the clean energy penetration (38.6%) and total annual load (3,974 TWh) in 2021 (EIA 2022a). Any scenarios to the right of the diamond indicate an increase in total clean energy penetration in 2040 compared to today's levels. Any scenarios above the diamond indicate a growth in total annual load compared to today's load.




*Note: Histogram (black bars along x- and y-axes) and contour (red topographical lines in center plot) axes are shown counts of scenarios. The diamond indicates 2021 levels (EIA 2022a). Thresholds separating the three scenario groups are shown as dashed lines, and each scenario group is labeled.*

***Figure VI-1. Counts of study scenarios describing the amount of clean energy generation (as percentage of total annual generation) and the total annual load in 2040.***

[55] Please refer to source documentation of each study to understand the specific generation mixes considered and modeled in each.

Three general groups of scenarios emerge from the contour plot, as shown by the outermost contour line in Figure VI-1. Using the contours as a guide, linear thresholds are applied to categorize scenarios into three groups:

- **Moderate/Moderate:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and moderate clean energy penetration between 2021 baseline (38.6%) and 80% in 2040; 2021 load and penetration values from EIA (2022a).
- **Moderate/High:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and high clean energy penetration above 80% in 2040.
- **High/High:** high load growth above 7,000 TWh and high clean energy penetration above 80% in 2040.

All studies considered scenarios with different utility, state, and federal power sector policies modeled—such as state clean energy standards or energy efficiency laws—based in part on the existing utility, state, and federal policies in place at the time of each study. It is important to note that modeling for all studies was performed before the passage of the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022 (IRA). It is anticipated that these laws will have dramatic impacts on future generation and demand that were not modeled among the business-as-usual and existing policy scenarios presented here (Jenkins et al. 2022b, Steinberg et al. 2023). Transmission solutions will be needed to accommodate the generation and load changes enabled by financial incentives included in both laws.

The Moderate/Moderate scenario group includes many scenarios that modeled various changes in market forces to drive changes in generation and load, ignoring any existing or new power sector policies. Nearly all studies' business-as-usual or reference scenarios fall into this scenario group. Some scenarios that considered new policies—such as 95% clean energy generation nationwide by 2050—also fall into this group. Scenarios from all six studies are represented in the Moderate/Moderate scenario group. The Moderate/Moderate scenario group most closely represents the evolution of the power system had the IIJA and IRA not been enacted and are, therefore, an unlikely representation of future power sector need.

The Moderate/High scenario group includes a diverse mix of different market forces and policy scenarios. Many scenarios that model 95% clean electricity generation by 2035 or 2040 fall into this group. Scenarios from all six studies are represented in the Moderate/High scenario group. On a nation-wide basis, the Moderate/High scenario group best represents the future power system that could be enabled by current (as of the publication date of this Needs Study) utility, local, state, and federal policies, including the large investments in clean generation technologies expected to be made possible by the IRA.[56] While these scenarios are now within

[56] Several studies anticipate that IRA will enable power sector carbon dioxide emissions to reduce by 70%–91% in 2030 compared with 2005 emissions (DOE 2022c; Jenkins et al. 2022a; Larsen et al. 2022; Mahajan et al. 2022; Roy et al. 2022; Steinberg et al. 2023). This most closely aligns with the power sector carbon dioxide emissions enabled by scenarios in the Moderate/High scenario group. The spread of 2030 carbon emissions reductions (compared with 2005 levels) for scenarios used in this analysis are 30%–72% for the Moderate/Moderate scenario group, 70%–80% for the Moderate/High scenario group, and 80% for the High/High scenario group. More details about the carbon emission reductions reached by all scenarios are found in the Supplemental Material.

the range of possibility given current policies, they are not inevitable and will require action—not least of which is the rapid upgrade of the Nation's transmission system—by the power sector community to achieve (Jenkins et al. 2022b; Steinberg et al. 2023).

The High/High scenario group only includes scenarios in which new policies are enacted, most notably policies that encourage high amounts of electrification and the adoption of energy intensive technologies. Certain regions (e.g., California, New England, New York) have decarbonization and load growth policies (NRRI 2021) more in line with the High/High scenario group assumptions. This group is dominated by scenarios from Denholm et al. (2022a), which model 100% clean electricity supply by 2035 to support large load growth from electrification, hydrogen production, and carbon capture and sequestration technologies to support economy-wide net-zero greenhouse gas emissions by 2050.

Only a few scenarios that fall outside these three scenario groups—notably those in which load growth from high electrification outpaces clean energy technology deployment—were considered by some studies (*see* Figure VI-1). Given the small sample size of scenarios outside the three categories identified here, they are not considered in this analysis. Furthermore, scenarios that disallowed building of interregional transmission were excluded from this analysis. Interregional transmission can be the most cost-effective solution to meet transmission needs in some circumstances, and experts have identified interregional solutions as critical to addressing emerging reliability and resilience needs. For that reason, we consider scenarios that arbitrarily disallow these solutions even where the models find them to be the cost-effective option too restrictive. Additional information about all study scenarios and which scenarios were included in each scenario group is found in the Supplemental Material.

## VI.b. Treatment of Alternative Transmission Solutions

There are several different combinations of generation and transmission solutions to meet regional electricity demands. Co-locating generation and storage units, siting generation close to load, and siting generation far from load with long transmission lines connecting the two are all examples of different solutions. Capacity expansion models will identify the least-cost choice among these combinations to meet reliability and load requirements.

Capacity expansion models quantify transmission capacity in terms of power carrying capacity (GW) or power carrying capacity across distance (GW-mi). These quantities are inherently technology neutral. When capacity expansion models find that new GW or GW-mi of transmission capacity is needed, this need could be met, at least in part, by increasing the carrying capacity of existing transmission infrastructure. For example, using DLRs or reconductoring existing transmission lines could enable transmission system operators to make better use of the full carrying capacity of existing transmission infrastructure. All results presented in the subsequent sections could be met with a combination of transmission technologies, both traditional and emerging alternatives. Additional engineering analysis performed by transmission planners is needed to determine the best technologies and locations of the available transmission solutions to meet the needs identified here.

Alternative transmission solutions could be used in addition to new traditional AC transmission lines to meet the needs identified here. These solutions include strategically placed generation near load centers, GETs, energy storage, and DERs. Any of these solutions could help lower, but are unlikely to eliminate, the need for new "poles and wires" transmission infrastructure. Some of these solutions are explicitly included in the capacity expansion modeling results analyzed here. The grid reliability services provided by many alternative solutions are not fully captured in capacity expansion modeling, however, but their value in reducing overall system costs is captured.

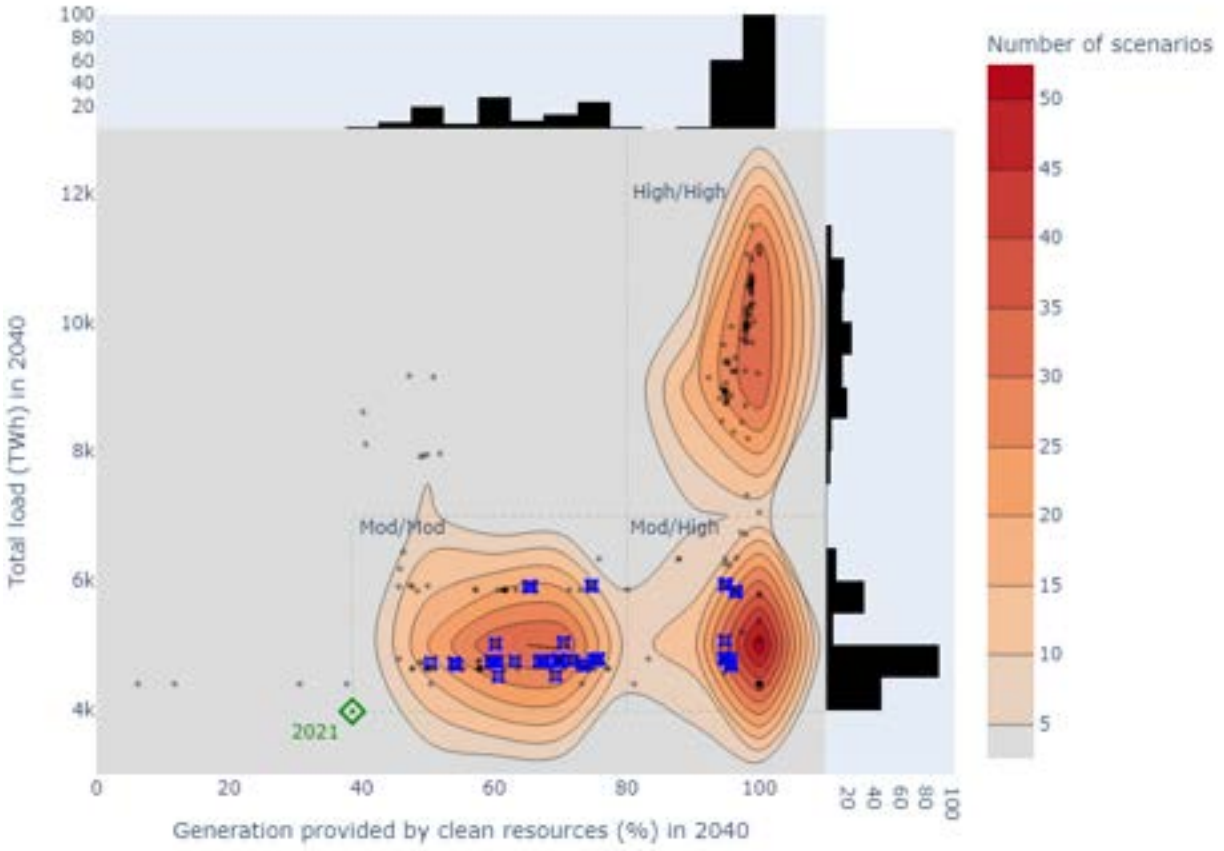
Energy storage resources enable a more efficient use of the grid and are increasingly important for grid reliability with increased demand from electrification (Ardani, et al. 2021). All studies except Larson, et al. (2021) co-optimize future capacity expansion of diurnal, stand-alone storage[57] among their respective suites of generation resources. The location of any new storage facilities identified by the models could be near generation or at key locations in the transmission network where their energy arbitrage and reserve services are most beneficial. All studies find large growth in energy capacity of storage technologies, notably batteries, under numerous scenarios to meet future power system changes. Storage capacity is found to increase from 1 GW of installed capacity in 2020 (EIA 2022) to between 25 GW and 325 GW in 2040 across all scenarios considered by Cole et al. (2021). Brown and Botterud (2020) find increased deployment of 3,500 GWh to 11,500 GWh of storage energy by 2040 with more storage necessary to balance a less coordinated grid.

As described in Section V.d., Vibrant Clean Energy's report, *Why Local Solar for All Costs Less* (Clack et al. 2020), considers the economic and social impacts of increased adoption of DERs, namely distributed solar photovoltaic systems. Clack et al. (2020) compares the results of two high DER scenarios with business-as-usual scenarios to measure those impacts. These scenarios consider approximately 200 and 300 TWh of annual distributed solar production, respectively, in 2040.

There are 47 scenarios in this analysis that include over 200 TWh of distributed solar generation in 2040: nine from Ardani et al. (2021) and 38 from Cole et al. (2021). Fourteen of these scenarios are in the Moderate/High scenario group, and the remaining are in the Moderate/Moderate scenario group. The 47 high DER scenarios are shown as blue boxes in Figure VI-2. All high DER scenarios contribute to the range of transmission and transfer capacity need identified in the subsequent sections.

High DER scenarios do not necessarily result in lower transmission or transfer capacity builds than other scenarios. Nearly half of the high DER scenarios in the Moderate/Moderate scenario group resulted in higher-than-average 2040 transmission deployment compared with all scenarios in that group. The high DER scenarios in the Moderate/High scenario group had lower-than-average 2040 transmission deployment compared to all scenarios in that group but were not among the lowest builds of the group. As found in Clack et al. (2020), new transmission infrastructure is needed to accommodate high DER penetration in some regions.

[57] Storage technologies considered include pumped hydro and between 2- and 12-hour durations of battery storage.




*Note: See Figure VI-1. Blue boxes indicate scenarios with at least 200 TWh of annual energy production from DERs.*

***Figure VI-2. Histograms and contour plot for all study scenarios describing the amount of clean energy generation (in percentage of total annual generation) and the total annual load in 2040 with high DER scenarios indicated.***

## VI.c. Within-Region Transmission Deployment

All studies calculated the amount of new transmission deployment within a region modeled to meet different future scenarios.[58] Given the diversity of future scenarios considered, a range of results is presented in the results shared here.

Transmission deployment is presented as the increase in carrying capacity (GW or TW) of a modeled power line multiplied by the length (miles) of the line. Quantifying power lines as GW-mi or TW-mi is convenient for capacity expansion models but is not a common practice in industry. Transmission planners and developers quantify power lines by their nominal voltage rating (kV) multiplied by the length (miles) of the line. In general, the higher the voltage rating

[58] Because the estimation of transmission miles used in the NREL *North American Renewable Integration Study* is from a vintage version of the ReEDS model, which underestimated mileage, those results are not used here. NREL is constantly updating its ReEDS model. Information about the model can be found in the Supplemental Materials.

and the shorter the power line, the more carrying capacity it has. Table VI-2 from NRRI (1987) provides approximate conversions between nominal voltage ratings and distances to carrying capacity for traditional AC transmission lines. By these conversions, a 100-mile, 345 kV rated line is equivalent to 86 GW-mi.

***Table VI-2. Approximate power carrying capabilities (MW) of uncompensated AC transmission lines at different voltage ratings and lengths from NRRI (1987).***

| Nominal Voltage (kV) → Line Length (miles) ↓ | 138 | 161 | 230 | 345 | 500 | 765 |
|---|---|---|---|---|---|---|
| **50** | 145 | 195 | 390 | 1,260 | 3,040 | 6,820 |
| **100** | 100 | 130 | 265 | 860 | 2,080 | 4,660 |
| **200** | 60 | 85 | 170 | 545 | 1,320 | 2,950 |
| **300** | 50 | 65 | 130 | 420 | 1,010 | 2,270 |
| **400** | NA | NA | 105 | 335 | 810 | 1,820 |
| **500** | NA | NA | NA | 280 | 680 | 1,520 |
| **600** | NA | NA | NA | 250 | 600 | 1,340 |

A summary of median new transmission deployment (in TW-mi) for the contiguous United States as a whole and each region is presented in Table VI-3 for all scenario groups in 2030, 2035, and 2040. National transmission deployment considers all within-region transmission in the contiguous United States, not including interregional transmission (described next in Section VI.d.). The values represent the cumulative new transmission deployed by the stated year, less the modeled 2020 system. The approximate amount of transmission that currently exists in each region from Denholm et al. (2022a) is provided in Figure VI-4 for reference.

Table VI-3 and Figure VI-3 through VI-6 show the model results of new transmission deployment within each region for each scenario group in 2030, 2035, and 2040. The range of results is skewed right for almost all regions, indicating that a minority of scenarios show very high transmission builds. The interquartile range (IQR) (middle 50% of result distribution) and the median are shown in these figures for each region separately.

***Table VI-3. Median of regional transmission deployment results for each study scenario group in 2030, 2035, and 2040. Both new transmission in TW-mi and percent growth from 2020 system are shown.***

| Region | 2020 TW-mi | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | TW-mi | % Growth | TW-mi | % Growth | TW-mi | % Growth |
| **CONUS** | 85.6 | Mod/Mod | 11.6 | 14% | 17.0 | 20% | 20.9 | 24% |
| **CONUS** | 85.6 | Mod/High | 23.4 | 27% | 54.5 | 64% | 42.2 | 49% |
| **CONUS** | 85.6 | High/High | 33.2 | 39% | 109.8 | 128% | 123.0 | 144% |
| **California** | 4.29 | Mod/Mod | 0.06 | 1.5% | 0.07 | 1.6% | 0.08 | 1.8% |
| **California** | 4.29 | Mod/High | 0.09 | 2.1% | 0.12 | 2.8% | 0.12 | 2.9% |
| **California** | 4.29 | High/High | 0.05 | 1.1% | 0.16 | 3.7% | 0.23 | 5.4% |
| **Mountain** | 3.48 | Mod/Mod | 1.46 | 42.1% | 1.66 | 47.9% | 1.86 | 53.5% |
| **Mountain** | 3.48 | Mod/High | 2.28 | 65.5% | 3.14 | 90.4% | 2.88 | 82.9% |
| **Mountain** | 3.48 | High/High | 3.12 | 89.7% | 6.00 | 173% | 7.69 | 221% |
| **Northwest** | 15.24 | Mod/Mod | 0.03 | 0.2% | 0.04 | 0.3% | 0.08 | 0.5% |
| **Northwest** | 15.24 | Mod/High | 0.07 | 0.4% | 0.54 | 3.5% | 0.00 | 0.0% |
| **Northwest** | 15.24 | High/High | 0.62 | 4.1% | 4.71 | 30.9% | 8.54 | 56.1% |
| **Southwest** | 5.66 | Mod/Mod | 0.41 | 7.3% | 0.63 | 11.2% | 0.78 | 13.7% |
| **Southwest** | 5.66 | Mod/High | 0.93 | 16.5% | 1.87 | 33.0% | 0.81 | 14.3% |
| **Southwest** | 5.66 | High/High | 2.75 | 48.7% | 6.69 | 118% | 7.64 | 135% |
| **Texas** | 6.43 | Mod/Mod | 2.78 | 43.2% | 4.35 | 67.7% | 5.68 | 88.3% |
| **Texas** | 6.43 | Mod/High | 6.04 | 93.9% | 9.00 | 140% | 9.60 | 149% |
| **Texas** | 6.43 | High/High | 3.33 | 51.8% | 7.27 | 113% | 8.72 | 136% |
| **Delta** | 3.36 | Mod/Mod | 0.01 | 0.2% | 0.15 | 4.6% | 0.40 | 12.0% |
| **Delta** | 3.36 | Mod/High | 0.39 | 11.5% | 1.65 | 49.2% | 1.37 | 40.8% |
| **Delta** | 3.36 | High/High | 2.98 | 88.7% | 7.76 | 231% | 8.79 | 262% |
| **Florida** | 2.97 | Mod/Mod | 0.00 | 0.0% | 0.08 | 2.7% | 0.15 | 5.0% |
| **Florida** | 2.97 | Mod/High | 0.06 | 2.1% | 0.81 | 27.3% | 1.04 | 35.1% |
| **Florida** | 2.97 | High/High | 0.01 | 0.3% | 0.73 | 24.4% | 1.04 | 34.9% |
| **Mid-Atlantic** | 14.60 | Mod/Mod | 0.56 | 3.9% | 0.96 | 6.5% | 1.11 | 7.6% |
| **Mid-Atlantic** | 14.60 | Mod/High | 1.09 | 7.5% | 3.28 | 22.5% | 3.61 | 24.7% |
| **Mid-Atlantic** | 14.60 | High/High | 2.49 | 17.1% | 8.84 | 60.5% | 11.69 | 80.1% |
| **Midwest** | 11.92 | Mod/Mod | 1.13 | 9.5% | 2.26 | 19.0% | 3.40 | 28.5% |

| Region | 2020 TW-mi | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | TW-mi | % Growth | TW-mi | % Growth | TW-mi | % Growth |
| **Midwest** | 11.92 | Mod/High | 3.71 | 31.2% | 13.34 | 112% | 16.22 | 136% |
| **Midwest** | 11.92 | High/High | 7.73 | 64.8% | 20.70 | 174% | 23.40 | 196% |
| **New England** | 1.94 | Mod/Mod | 0.02 | 0.9% | 0.03 | 1.6% | 0.05 | 2.4% |
| **New England** | 1.94 | Mod/High | 0.05 | 2.5% | 0.10 | 5.2% | 2.72 | 140% |
| **New England** | 1.94 | High/High | 0.37 | 18.9% | 2.44 | 126% | 2.98 | 154% |
| **New York** | 0.82 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **New York** | 0.82 | Mod/High | 0.00 | 0.0% | 0.00 | 0.0% | 0.06 | 7.6% |
| **New York** | 0.82 | High/High | 0.10 | 12.5% | 0.38 | 46.1% | 0.41 | 50.4% |
| **Plains** | 6.97 | Mod/Mod | 1.56 | 22.4% | 2.93 | 42.1% | 3.93 | 56.3% |
| **Plains** | 6.97 | Mod/High | 3.52 | 50.5% | 8.32 | 119% | 6.31 | 90.5% |
| **Plains** | 6.97 | High/High | 6.88 | 98.7% | 28.47 | 408% | 31.26 | 449% |
| **Southeast** | 8.90 | Mod/Mod | 0.55 | 6.2% | 1.09 | 12.2% | 1.58 | 17.7% |
| **Southeast** | 8.90 | Mod/High | 2.83 | 31.8% | 6.82 | 76.6% | 6.04 | 67.9% |
| **Southeast** | 8.90 | High/High | 2.68 | 30.1% | 9.11 | 102% | 11.46 | 129% |

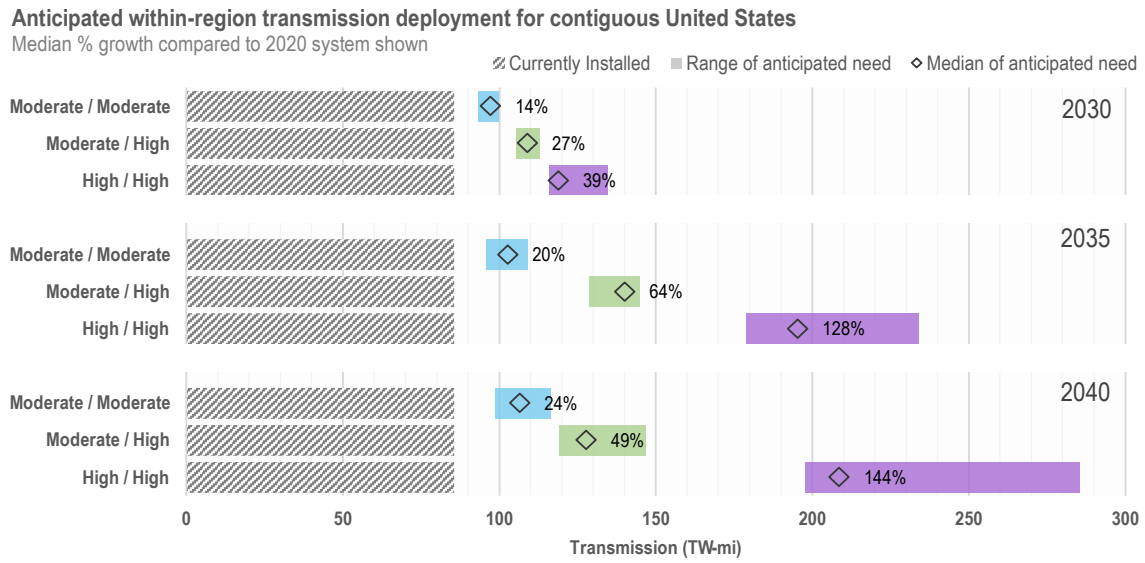
*Note: The 2020 existing system for each region is taken from Denholm et al. (2022a). While median results are cumulative and not incremental, the median 2040 transmission deployment appears to be lower than the 2035 median for some regions, especially in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which modeled lower transmission builds in many regions compared to other studies included in this analysis, bringing the median result lower for this year compared to 2035.*

Figure VI-3 shows the interquartile range of national transmission deployment results for all three scenario groups in 2030, 2035, 2040. National transmission deployment considers all within-region transmission in the contiguous United States, not including interregional transmission. As expected, more clean energy generation and load growth require more transmission to be deployed to maintain reliable power system operations into the future. In 2030, median within-region transmission deployment is needed to grow by 27% to meet the power sector demands of the Moderate/High scenario group and by 39% for the High/High scenario group.

Figure VI-4 shows the transmission results for the Moderate/Moderate scenario group, which defines a power system without the IIJA and IRA enacted. Studies consistently find that the largest transmission expansion will take place in Texas to meet future power sector changes across all years. In 2035, the median transmission expansion in Texas is 4,350 GW-mi, nearly 70% of its 2020 size. Transmission is expanded more in the Mountain region (2035 median of 1,660 GW-mi, nearly 50% current size) than other regions in the Western Interconnection. In the Eastern Interconnection, modeling results show the most transmission expansion in the Southeast (1,090 GW-mi, 12% growth by 2035), Midwest (2,260 GW-mi, 19% growth), and Plains (2,930 GW-mi, 42% growth).

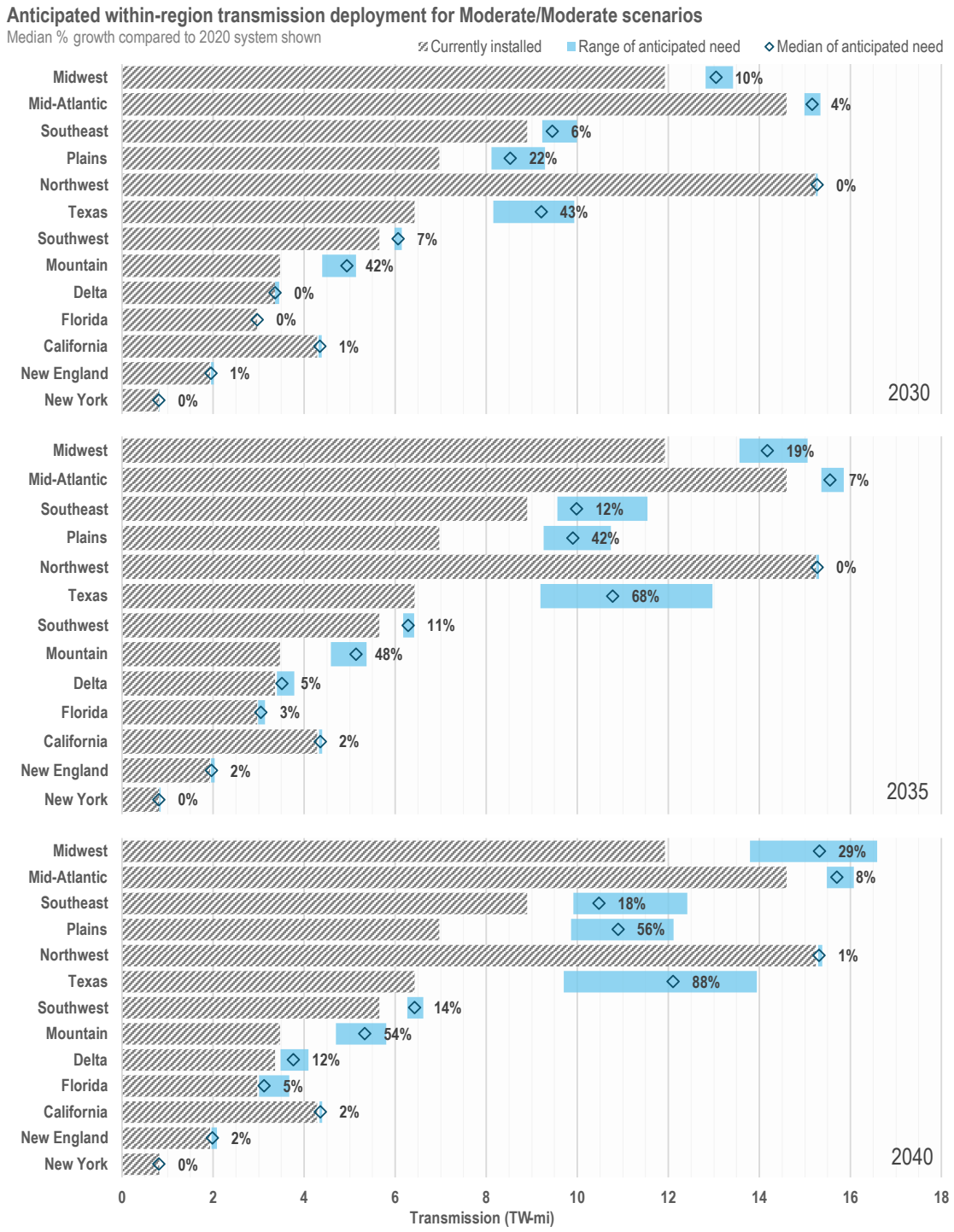
Figure VI-5 shows the results for the Moderate/High scenario group, which, at the time of publication, represents a likely power sector future given recently enacted laws. The regional trends are similar in this scenario group as the previous, with the largest transmission expansion again occurring in the Texas, Mountain, Southeast, Midwest, and Plains regions. These regions also have large IQRs of expansion results compared with other regions. The median transmission expansion in 2035 in Texas is 9,000 GW-mi, a 140% growth compared with the 2020 system. Scenario results suggest that the transmission system in the Mountain, Plains, and Midwest regions will double in size by 2035 to meet the power sector needs modeled in this scenario group (2035 median expansion values of 3,140 GW-mi, 8,320 GW-mi, and 13,340 GW-mi, respectively). These results demonstrate the heavy reliance on clean energy in the middle of the contiguous United States that must be connected to a reinforced power grid to serve load centers.

Figure VI-6 shows the results for the High/High scenario group. These scenarios assume high economy-wide decarbonization and load growth nationwide, which will not be realized throughout the nation without additional state and federal policies. Insights about particular regions with high decarbonization or load growth goals (e.g., California, New York, and New England) (NRRI 2021) can be gained from results in this scenario group. However, these scenarios do assume that all regions of the country are on a similar decarbonization trajectory. This group results in the most transmission expansion, which is necessary to meet the high load growth—driven predominantly by electrification and industrial hydrogen production—scenarios in this group. Additional transmission in the Midwest and Plains greatly exceeds that of all other regions under the high load growth scenarios, again pointing to the large reliance on transmission to access low-cost generation in the middle of the United States. The Southeast and Delta regions also experience large transmission builds—a doubling and tripling of the 2020 system, respectively—in this scenario group compared to the lower load growth scenarios.



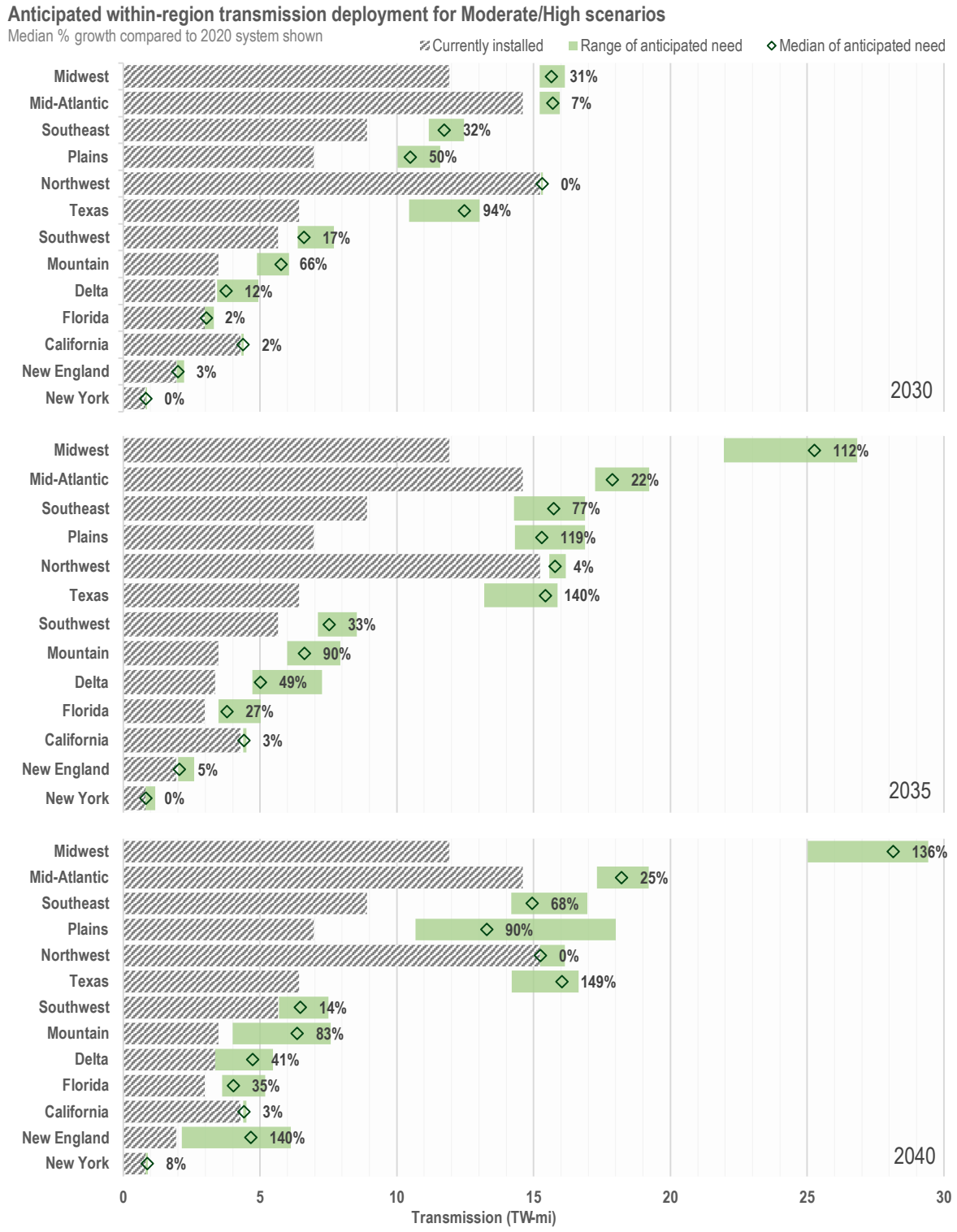

*Note: New transmission relative to the 2020 system is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a). While results are cumulative and not incremental, the 2040 transmission deployment appears to be lower than the 2035 in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which models lower transmission builds in many regions compared with other studies included in this analysis, bringing the median result lower for this year compared to 2035.*

***Figure VI-3. Regional transmission deployment for contiguous United States across all scenario groups.***



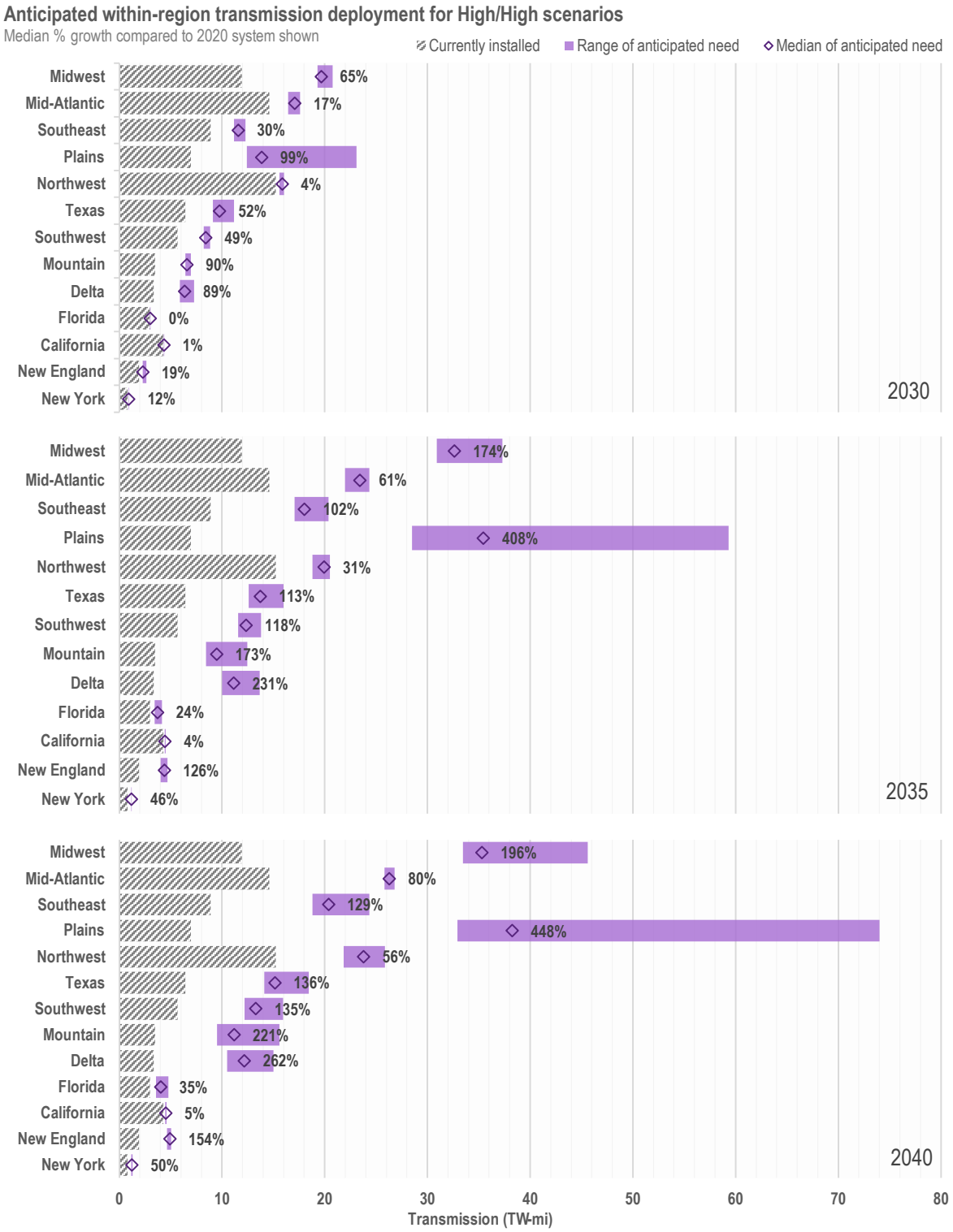

*Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).*

***Figure VI-4. Regional transmission deployment for all scenarios in the Moderate/Moderate scenario group.***




*Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).*

***Figure VI-5. Regional transmission deployment for all scenarios in the Moderate/High scenario group.***




*Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).*

***Figure VI-6. Regional transmission deployment for all scenarios in the High/High scenario group.***

# VI.d. Interregional Transfer Capacity

Whereas the previous set of results focused on new transmission deployment *within* a region to meet growing demand, this section focuses on new transfer capacity needed *between* regions. Capacity on a transmission line means the ability to transfer power without causing facility overloads under contingency and is calculated considering the electrical and physical parameters of the line given the normal ambient conditions in its location. Transfer capacity, in turn, means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines or paths between those areas under specified system conditions. Transfer capacity has many benefits. For one, regional grid reliability and resilience is strengthened by the diversity of generation by geographic location and energy resource type provided by interregional transfers. Regions are also able to import electricity when they cannot meet growing demand with local generation or when the combination of remote generation and interregional transmission has lower overall system costs than local generation. Conversely, regions are able to export excess electricity to offset the costs for consumers in their region.

Transfer capacity differs from transmission deployment results in the previous section by focusing on the amount of power that new or upgraded transmission lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries. For that reason, transfer capacity results are shown as GW of power between regions, instead of as GW-mi of new transmission lines. The amount of transfer capacity needed between regions to support different futures was calculated by all studies except Larson et al. (2021), which reports deployment only in capacity-miles and not capacity alone.

A summary of the median new transfer capacity results (in GW) for the contiguous United States as a whole and each region is presented in Table VI-4. It is reasonable to assume that increased transfers between regions not modeled by the studies considered here would decrease the size of transfers modeled between other regions. For example, if capacity expansion studies had considered increased transfers between Texas and the Southwest, then the resulting transfers between Texas and the Plains may have decreased. But these shifts in transfer capacities with different neighbors are unlikely to be equivalent. Interregional transfers can offer several operational benefits, such as resource diversification, in addition to just energy capacity access. Planning models may optimize for a solar energy-rich region to increase its transfer capacity with a neighboring region with excess geothermal resources, for example, rather than with a neighbor similarly rich in solar energy. Studies find this to be true for the New England region, where increased transfer capabilities with hydropower resources in Canada can be used to balance offshore wind generation (Dimanchev et al. 2020; Jones et al. 2020).

Table VI-4 for all scenario groups in 2030, 2035, and 2040. National transfer capacity considers all interregional transmission in the contiguous United States, not including within-region transmission deployment. The approximate amount of transfer capacity that currently exists among all regions is provided for reference. Data from Denholm et al. (2022a) were used to approximate the existing transfer capacities between regions, as it is the most up to date of all studies.

Three interregional transfers in Table VI-4 and the subsequent figures—Mountain to Plains, Plains to Texas, and Plains to Southwest—represent increased transfer across the three interconnections. These transfer capacities are modeled as increased DC intertie connections, like those connections that already exist between the interconnections.

Links between neighboring regions are absent from Table VI-4 and subsequent figures if they were not considered by the modelers. For example, the potential creation of an offshore transmission system to support Atlantic offshore wind generation may allow the New England and Mid-Atlantic regions to share direct transfers without needing to transfer through the terrestrial New York system. None of the studies considered here modeled this connection so it is not included here. Also missing are international transfers with Canada or Mexico. Only Brinkman et al. (2021) considers international transfers, and only for scenarios in the Moderate/Moderate scenario group. Given the small sample size, these transfers are excluded here but can be found in the Supplemental Material.

There is currently no transmission connection between Texas and the Mountain, Southwest, or Delta regions (ERCOT 2022a). None of the studies considered here model new future connections between Texas and the Mountain or Southwest regions. Brown and Botterud (2020) is the only study that models new future connections between Texas and the Delta, and only for the year 2040.[59] These results are excluded from the table because of the small sample size. All other studies only assumed transfer capacity expansion between Texas and the Plains.

It is reasonable to assume that increased transfers between regions not modeled by the studies considered here would decrease the size of transfers modeled between other regions. For example, if capacity expansion studies had considered increased transfers between Texas and the Southwest, then the resulting transfers between Texas and the Plains may have decreased. But these shifts in transfer capacities with different neighbors are unlikely to be equivalent. Interregional transfers can offer several operational benefits, such as resource diversification, in addition to just energy capacity access. Planning models may optimize for a solar energy-rich region to increase its transfer capacity with a neighboring region with excess geothermal resources, for example, rather than with a neighbor similarly rich in solar energy. Studies find this to be true for the New England region, where increased transfer capabilities with hydropower resources in Canada can be used to balance offshore wind generation (Dimanchev et al. 2020; Jones et al. 2020).

***Table VI-4. Median regional transfer capacity results for each scenario group in 2030, 2035, and 2040. Both new transfer capacity in GW and percent growth from 2020 system are shown.***

| Regional Pair | 2020 GW | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | GW | % Growth | GW | % Growth | GW | % Growth |
| **CONUS** | 109 | Mod/Mod | 15.5 | 14% | 27.5 | 25% | 37.6 | 34% |
| **CONUS** | 109 | Mod/High | 33.2 | 30% | 124.6 | 114% | 239.4 | 219% |

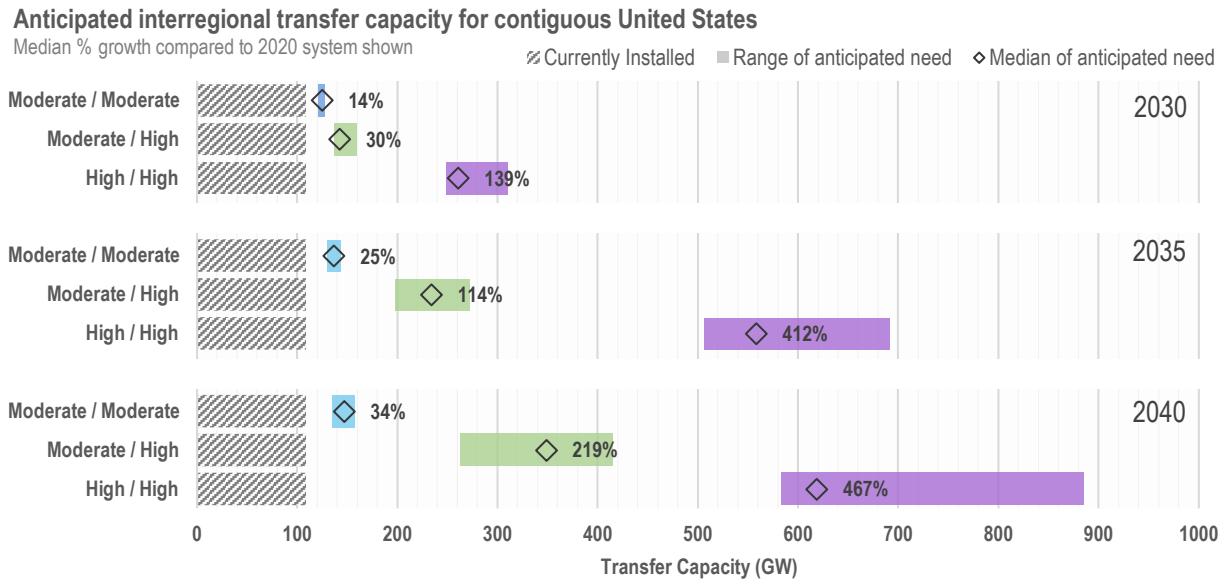
[59] The median transfer capacities between Texas and the Delta are 22.2 GW in the Moderate/Moderate scenario group, 48.3 GW in the Moderate/High scenario group, and 106.7 GW in the High/High scenario group in 2040 for scenarios considered by Brown and Botterud (2020).

| Regional Pair | 2020 GW | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | GW | % Growth | GW | % Growth | GW | % Growth |
| **CONUS** | 109 | High/High | 151.5 | 139% | 449.0 | 412% | 509.5 | 467% |
| **California – Mountain** | 2.12 | Mod/Mod | 0.31 | 14.7% | 0.96 | 45.4% | 1.80 | 84.8% |
| **California – Mountain** | 2.12 | Mod/High | 0.58 | 27.3% | 1.87 | 88.1% | 4.97 | 235% |
| **California – Mountain** | 2.12 | High/High | 1.21 | 57.0% | 2.75 | 130% | 4.31 | 204% |
| **California – Northwest** | 5.15 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **California – Northwest** | 5.15 | Mod/High | 0.00 | 0.0% | 0.13 | 2.5% | 0.00 | 0.1% |
| **California – Northwest** | 5.15 | High/High | 0.25 | 4.8% | 1.28 | 24.9% | 1.94 | 37.7% |
| **California – Southwest** | 5.23 | Mod/Mod | 0.00 | 0.0% | 0.14 | 2.7% | 0.22 | 4.3% |
| **California – Southwest** | 5.23 | Mod/High | 0.05 | 0.9% | 0.31 | 5.9% | 5.09 | 97.3% |
| **California – Southwest** | 5.23 | High/High | 1.90 | 36.4% | 5.31 | 102% | 6.89 | 132% |
| **Mountain – Northwest** | 12.7 | Mod/Mod | 0.00 | 0.0% | 0.09 | 0.7% | 0.51 | 4.0% |
| **Mountain – Northwest** | 12.7 | Mod/High | 1.08 | 8.5% | 3.30 | 26.0% | 0.00 | 0.0% |
| **Mountain – Northwest** | 12.7 | High/High | 6.25 | 49.2% | 25.7 | 202% | 39.2 | 308% |
| **Mountain – Southwest** | 4.06 | Mod/Mod | 0.04 | 0.9% | 0.09 | 2.2% | 0.38 | 9.5% |
| **Mountain – Southwest** | 4.06 | Mod/High | 0.37 | 9.1% | 1.65 | 40.6% | 1.70 | 41.7% |
| **Mountain – Southwest** | 4.06 | High/High | 2.08 | 51.2% | 5.24 | 129% | 6.06 | 149% |
| **Mountain – Plains** | 0.92 | Mod/Mod | 0.36 | 39.1% | 0.94 | 102% | 1.40 | 152% |
| **Mountain – Plains** | 0.92 | Mod/High | 0.79 | 85.4% | 2.64 | 287% | 11.9 | 1,290% |
| **Mountain – Plains** | 0.92 | High/High | 6.10 | 663% | 19.3 | 2100% | 29.2 | 3,170% |
| **Plains – Southwest** | 0.40 | Mod/Mod | 0.69 | 172% | 1.16 | 290% | 1.48 | 370% |
| **Plains – Southwest** | 0.40 | Mod/High | 2.53 | 631% | 3.66 | 914% | 13.1 | 3,280% |
| **Plains – Southwest** | 0.40 | High/High | 5.54 | 1380% | 13.0 | 3,240% | 14.4 | 3,600% |
| **Plains – Texas** | 0.82 | Mod/Mod | 0.02 | 3.0% | 0.49 | 60.0% | 0.91 | 111% |
| **Plains – Texas** | 0.82 | Mod/High | 1.15 | 140% | 9.84 | 1,200% | 14.6 | 1,780% |
| **Plains – Texas** | 0.82 | High/High | 14.3 | 1750% | 28.9 | 3,520% | 34.9 | 4,260% |
| **Delta – Midwest** | 3.00 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **Delta – Midwest** | 3.00 | Mod/High | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **Delta – Midwest** | 3.00 | High/High | 0.10 | 3.2% | 0.91 | 30.4% | 1.32 | 44.2% |
| **Delta – Plains** | 4.76 | Mod/Mod | 0.00 | 0.0% | 0.35 | 7.4% | 0.73 | 15.3% |
| **Delta – Plains** | 4.76 | Mod/High | 4.89 | 103% | 19.7 | 414% | 0.00 | 0.0% |
| **Delta – Plains** | 4.76 | High/High | 20.7 | 434% | 48.5 | 1020% | 55.3 | 1160% |
| **Delta – Southeast** | 5.92 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **Delta – Southeast** | 5.92 | Mod/High | 0.92 | 15.6% | 5.10 | 86.2% | 10.7 | 181% |
| **Delta – Southeast** | 5.92 | High/High | 10.1 | 171% | 33.9 | 572% | 37.7 | 637% |

| Regional Pair | 2020 GW | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | GW | % Growth | GW | % Growth | GW | % Growth |
| **Florida – Southeast** | 3.60 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **Florida – Southeast** | 3.60 | Mod/High | 0.00 | 0.0% | 1.14 | 31.6% | 7.20 | 200% |
| **Florida – Southeast** | 3.60 | High/High | 0.87 | 24.2% | 10.6 | 295% | 12.9 | 360% |
| **Mid-Atlantic – Midwest** | 21.7 | Mod/Mod | 1.10 | 5.1% | 2.39 | 11.0% | 2.65 | 12.2% |
| **Mid-Atlantic – Midwest** | 21.7 | Mod/High | 9.87 | 45.5% | 33.8 | 156% | 21.9 | 101% |
| **Mid-Atlantic – Midwest** | 21.7 | High/High | 42.4 | 196% | 103 | 475% | 119 | 550% |
| **Mid-Atlantic – New York** | 2.00 | Mod/Mod | 0.00 | 0.0% | 0.29 | 14.7% | 0.81 | 40.6% |
| **Mid-Atlantic – New York** | 2.00 | Mod/High | 0.00 | 0.0% | 2.43 | 122% | 14.8 | 742% |
| **Mid-Atlantic – New York** | 2.00 | High/High | 2.03 | 102% | 8.24 | 412% | 12.7 | 634% |
| **Mid-Atlantic – Southeast** | 7.07 | Mod/Mod | 0.19 | 2.6% | 0.51 | 7.3% | 1.50 | 21.3% |
| **Mid-Atlantic – Southeast** | 7.07 | Mod/High | 2.78 | 39.3% | 6.86 | 97.1% | 12.5 | 177% |
| **Mid-Atlantic – Southeast** | 7.07 | High/High | 4.36 | 61.7% | 9.88 | 140% | 12.2 | 173% |
| **Midwest – Plains** | 12.1 | Mod/Mod | 1.35 | 11.2% | 3.14 | 26.0% | 3.62 | 30.1% |
| **Midwest – Plains** | 12.1 | Mod/High | 7.99 | 66.3% | 21.1 | 175% | 23.0 | 191% |
| **Midwest – Plains** | 12.1 | High/High | 24.6 | 204% | 88.0 | 731% | 98.7 | 819% |
| **Midwest – Southeast** | 8.27 | Mod/Mod | 0.00 | 0.0% | 0.00 | 0.0% | 0.00 | 0.0% |
| **Midwest – Southeast** | 8.27 | Mod/High | 1.28 | 15.4% | 4.46 | 53.9% | 6.23 | 75.3% |
| **Midwest – Southeast** | 8.27 | High/High | 10.3 | 125% | 34.4 | 416% | 39.9 | 483% |
| **New England – New York** | 2.03 | Mod/Mod | 1.46 | 71.7% | 2.84 | 140% | 2.90 | 142% |
| **New England – New York** | 2.03 | Mod/High | 1.53 | 75.1% | 5.19 | 255% | 11.4 | 559% |
| **New England – New York** | 2.03 | High/High | 3.96 | 195% | 17.0 | 835% | 21.4 | 1050% |

*Note: The 2020 existing national system for each region is taken from Denholm et al. (2022a). While median results are cumulative and not incremental, the median 2040 transmission deployment appears to be lower than the 2035 median for some interregional pairs, especially in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which models lower transmission builds in many regions compared with other studies included in this analysis, bringing the median result lower for this year compared to 2035.*

Figure VI-7 through Figure VI-10 show the amount of interregional transfer capacity (in GW) needed between all regions for each of the three scenario groups in 2030, 2035, and 2040. Figure VI-7 shows the total interregional transfers within the contiguous United States. Like the previous set of results, the IQR (middle 50% of the distribution) and the median of all results are shown in these figures for each regional transfer separately. Additional, common statistical values can be found in the Supplemental Material for each scenario group.




*Note: New transfer capacity relative to the 2020 system is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).*

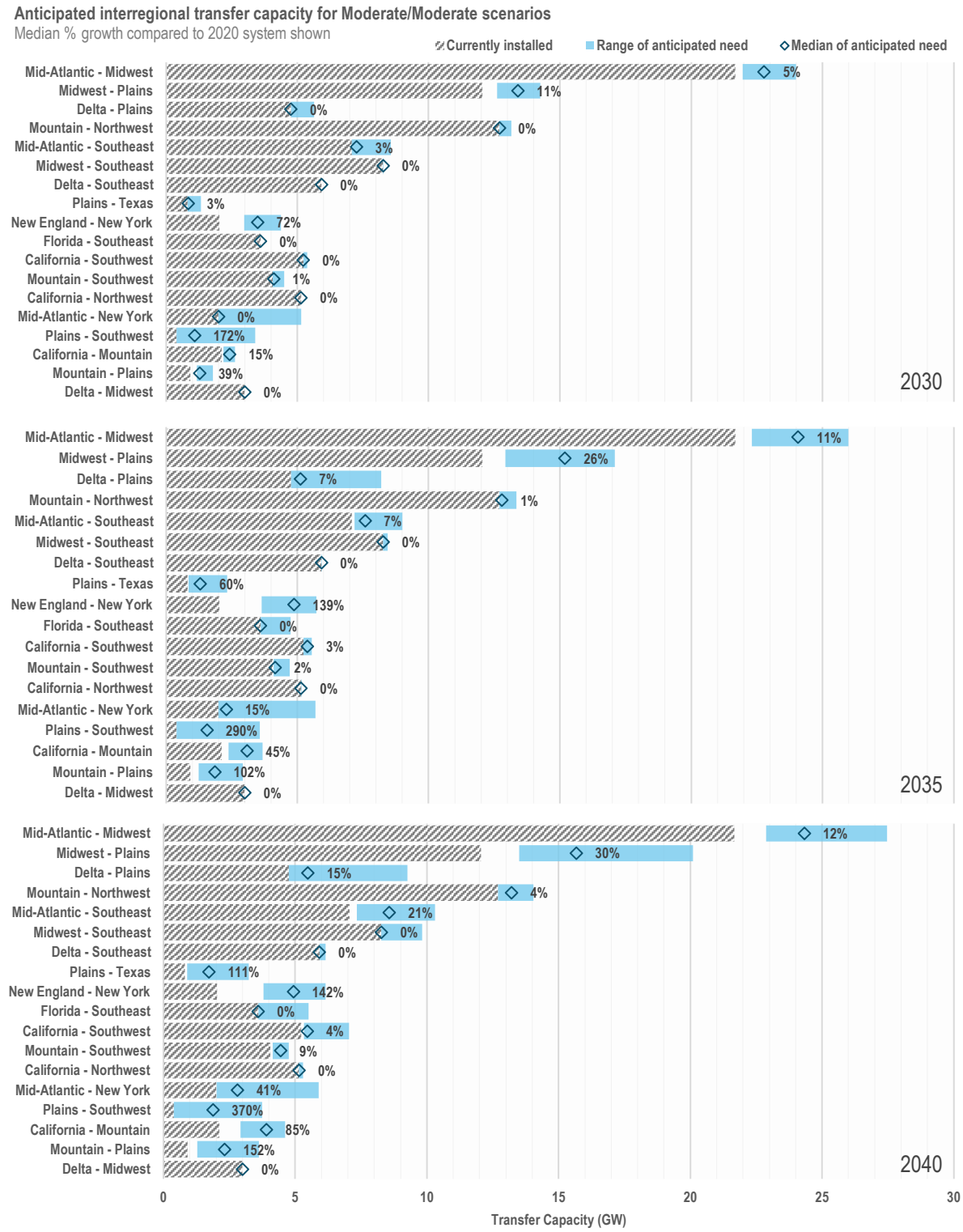
***Figure VI-7. Interregional transfer capacity for contiguous United States across all scenario groups.***

Figure VI-8 shows the required interregional transfer capacity for the Moderate/Moderate scenario group in 2030, 2035, and 2040, which defines a power system without the IIJA and IRA enacted. These results are relatively low, indicating that local generation within a region can meet regional demand needs for modeled scenarios in this group. There is moderate transfer capacity expansion in the northern half of the Eastern Interconnection. Highest transfers are found between New England and New York (2035 median of 2.8 GW, 140% growth) and between the Midwest and Plains (2035 median of 3.1 GW, 26% growth). Models show a range of increased transfer between the Eastern and Western Interconnections through the Plains and Southwest. In 2040, the median new transfer capacity between these two regions is 1.5 GW, a small absolute number but a nearly 370% increase from the current transfer capacity.

Figure VI-9 shows the required interregional transfer capacity for the Moderate/High scenario group in 2030, 2035, and 2040, which, at the time of publication, is the most likely power sector future given recently enacted laws. Capacity transfers in the Eastern Interconnection continue to dominate in this scenario group, but with increased expansion in new regions. Although new transfer capacity continues to grow between New York and New England and between the Plains and Midwest, higher clean energy generation results in cost-effective transfers between other regions compared with the last group. Median transfers between the Delta and the Plains grow fivefold from 2020 and 2035, adding 20 GW of new transfer capacity. The highest median transfer capacity is found between the Mid-Atlantic and the Midwest (34 GW in 2035), likely to move low-cost clean generation in the Plains and Midwest regions to the Mid-Atlantic. Cross-interconnection transfers between Texas and its eastern neighbors grow dramatically in this scenario group. In 2040, an estimated 15 GW of new transfer capacity could be built cost

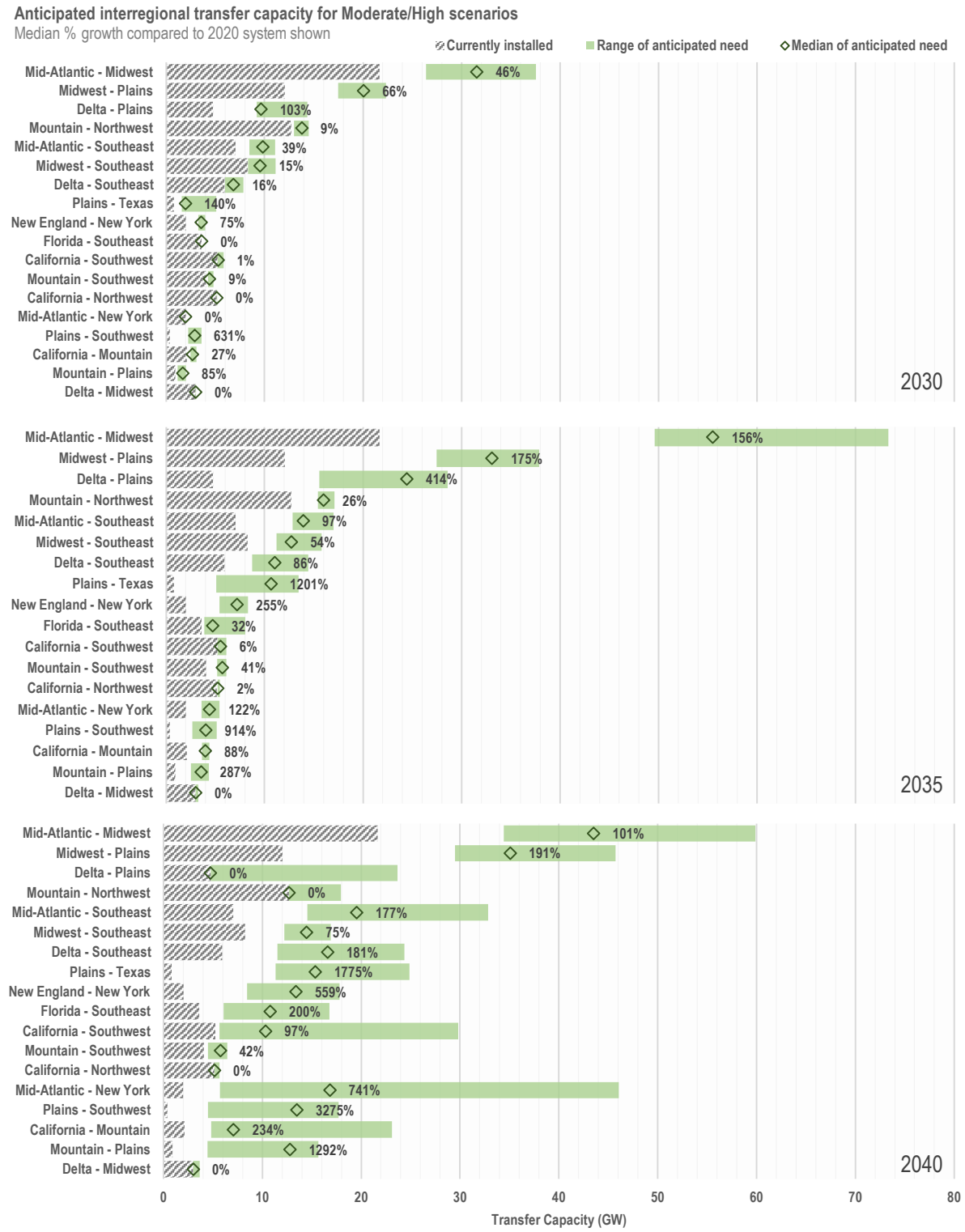
effectively between Texas and the Plains and an estimated 48 GW between Texas and the Delta region.

Figure VI-10 shows the required interregional transfer capacity for the High/High scenario group in 2030, 2035, and 2040, which will not be realized nationwide without additional state and federal policies. Estimated transfer capacity between regions quadruples in the high load growth scenarios compared to the Moderate/High scenario group. An increasingly interconnected grid increases reliability, especially in high clean energy and high load futures (Bloom et al. 2020; Brown and Botterud 2020; Denholm et al. 2022a), and that is reflected in these results of increased sharing among all regions. Transfer capacities between the Midwest, Plains, and their adjacent neighbors dominate in this scenario group, as increased access to low-cost generation in the middle of the country becomes more important to meet high demand. Increased transfers between the Eastern and Western Interconnections also grow considerably in this scenario group.



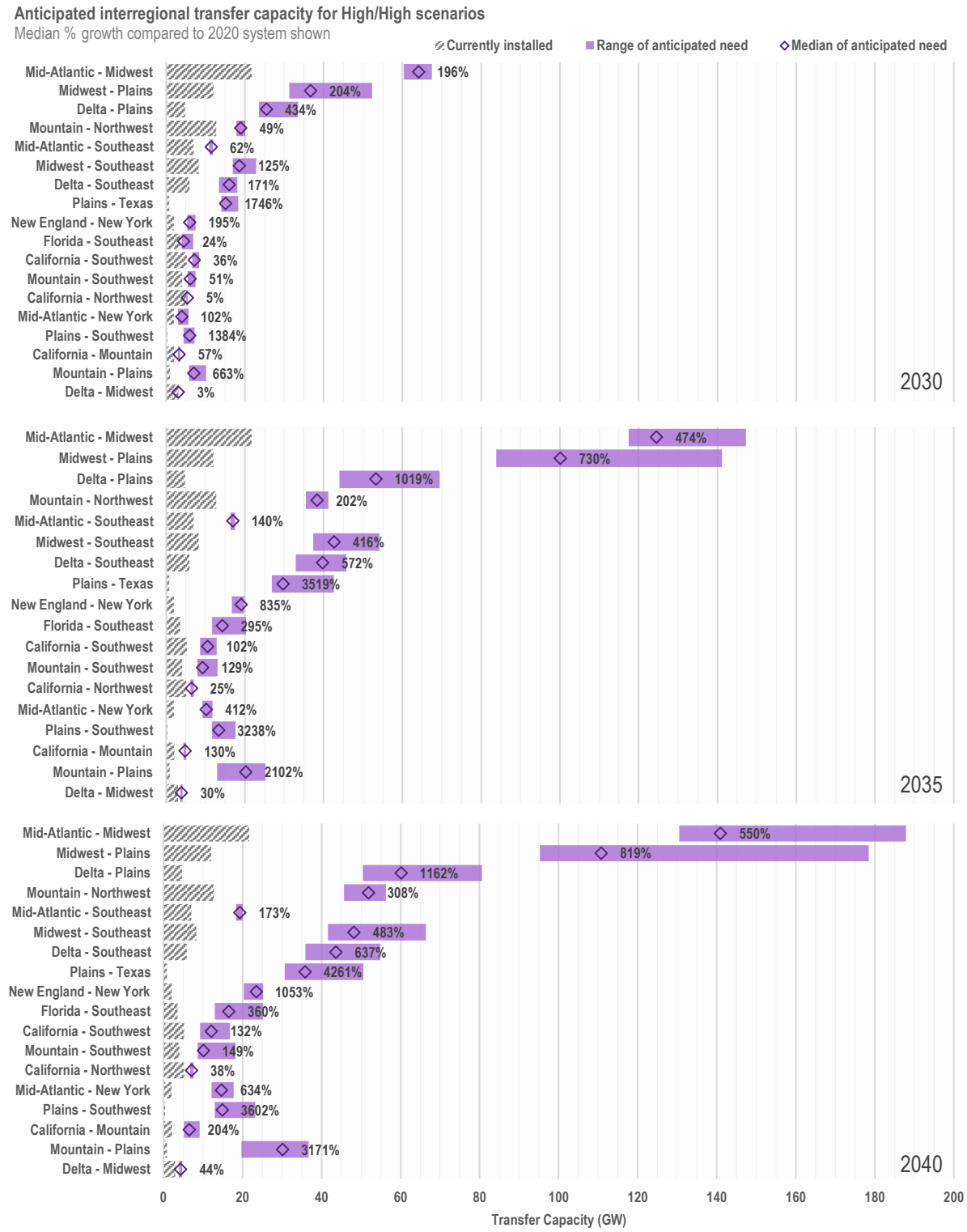

*Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).*

***Figure VI-8. Interregional transfer capacity for all scenarios in the Moderate/Moderate scenario group.***




*Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).*

***Figure VI-9. Interregional transfer capacity for all scenarios in the Moderate/High scenario group.***




*Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).*

***Figure VI-10. Interregional transfer capacity for all scenarios in the High/High scenario group.***

# VI.e. Comparison with Utility Plans

It is instructive to consider how current transmission utility plans for additional transmission development compare with anticipated future need revealed in the capacity expansion models considered here. Transmission planning is conducted by transmission owners and regional planning organizations to identify transmission projects expected to be needed to meet reliability and other needs. In most cases, local and regional transmission planning is conducted pursuant to FERC rules and regulations that govern the planning process and require certain minimum inputs. Interregional transmission planning is not required under these rules and regulations and the transmission plans reviewed for this study typically did not include interregional transmission needs, which in some regions (e.g., California, Northwest, Delta, Mid-Atlantic, New England, and New York) make up the bulk of anticipated transmission needs. Because few interregional plans exist, we compare utility transmission plans with the within-region transmission deployment results presented in Section VI.c. above.

Additionally, the inputs and scenarios used to create utility plans may not reflect evolving clean energy or electrification goals, which would drive additional need not reflected here. Moreover, transmission plans do not alleviate transmission needs on their own or guarantee that needed facilities will be built. Therefore, even in regions where robust utility and long-range transmission plans have been adopted in line with anticipated future transmission needs, additional action may be necessary (e.g., siting and permitting efforts) to ensure those needs are met.

NERC collects data on 10-year projections of bulk power system supply, demand, and delivery as part of its annual Long-Term Reliability Assessment process (NERC 2021) and publishes these data in its Electricity Supply and Demand database (NERC 2022c). These data include the near-term transmission development plans in each NERC assessment area, most through 2032 but some into future years. All transmission projects indicated as completed, delayed, planned, or under construction in NERC (2022c) are counted as "utility plans" for each region.

In addition, conceptual projects were considered from many of the long-term or public policy plans published by some of the regional transmission planning organizations,[60] shown in Table VI-4, which are not yet captured in the NERC Energy Supply and Demand database. The transmission projects included in these plans are at different stages of development; some have been approved by the transmission planning organizations' boards and development activities are underway, while others are hypothetical lines used for preliminary engineering analysis. It is possible that not all these conceptual projects will be built, and those that are built may not be in service by 2035. Comparing both the established utility plans and the conceptual, long-term projects against the capacity expansion modeling results provides insight into the general trajectory of transmission planning and development in each region against the anticipated

[60] Here, transmission planning organizations include the FERC Order 1000 regions and ERCOT. The scope of long-term transmission plans considered is limited to only to those published by these regional entities and not all local transmission utility plans—such as integrated resource plans—to keep the scope manageable.

need.[61] Not all of the FERC Order 1000 regional planning organizations have conducted such long-term or public policy plans in recent years.

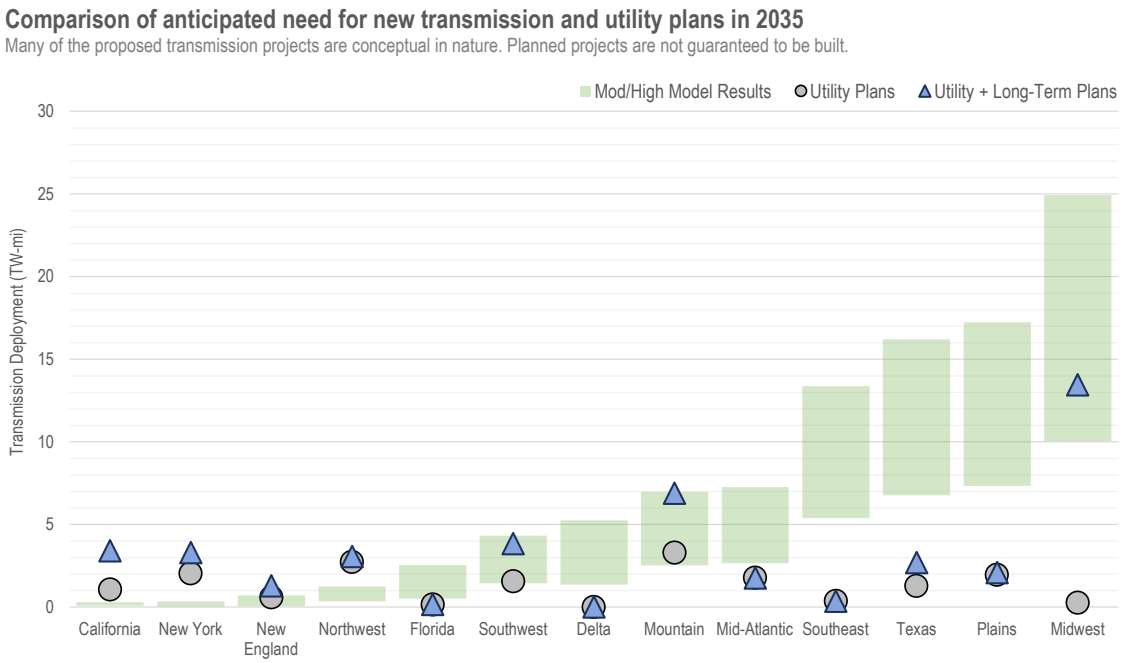
The utility plans as captured by NERC (2022c) of developers in each region meet or exceed the anticipated 2035 transmission need of the Moderate/High scenario group in the California, New York, New England, Northwest, and Mountain regions. The utility plans in the Southwest and Midwest regions also meet the anticipated 2035 need when considering long-term and public policy transmission plans, although some included projects may not yet be approved or placed in service by 2035. Considered transmission plans in all other regions—the Florida, Delta, Mid-Atlantic, Southeast, Texas, and Plains regions—do not meet this anticipated need.

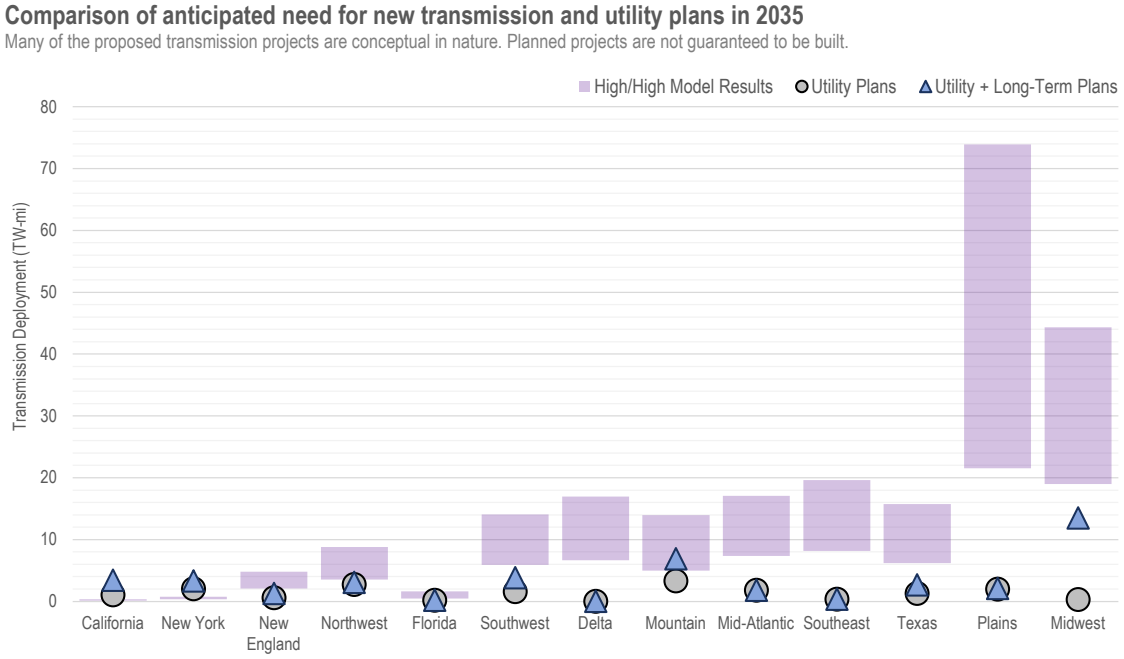
Many of the states and electric utilities in the aforementioned regions where existing utility and long-term plans exceed anticipated 2035 need under Moderate/High scenario group assumptions have decarbonization and load growth policies more in line with the High/High scenario group assumptions (NRRI 2021). When compared with results from the 2035 High/High scenario group—as shown in the bottom panel of Figure VI-7—only long-term plans in the California, New York, and Mountain regions continue to meet the anticipated transmission need. Several regions may need to develop additional transmission plans to meet their established decarbonization goals.

***Table VI-5. Transmission projects from recent long-term and public policy transmission plans published by several transmission planning organizations.***

| Organization | Long-Term/Public Policy Transmission Plan | Included Project Category | Reference |
|---|---|---|---|
| **CAISO** | 20-Year Transmission Outlook | • SB100 July 22 workshop projects<br>• Other relevant projects<br>• ISO system transmission development<br>• Offshore wind transmission development | CAISO 2022b |
| **ERCOT** | Long-Term West Texas Export Study | • Option 1 conceptual portfolio | ERCOT 2022b |
| **ISO-NE** | 2050 Transmission Study: Solution Development Update Dec 2022 | • Primary Solution Set: Preliminary overhead line rebuilds<br>• Primary Solution Set: Boston area preliminary solutions | ISO-NE 2022b |
| **ISO-NE** | 2050 Transmission Study: Solution Development Update Apr 2023 | • Primary Solution Set: Vermont preliminary solutions<br>• Primary Solution Set: North–South preliminary solutions<br>• Primary Solution Set: Boston import preliminary solutions | ISO-NE 2023 |
| **MISO** | MTEP21 Report Addendum: Long-Range Transmission Planning Tranche 1 | • LTRP Tranche 1 Portfolio | MISO 2022a |
| **MISO** | Long-Range Transmission Plan: Tranche 2 | • Draft hypothesis transmission set | MISO 2022b |
| **MISO-SPP** | Joint Targeted Interconnection Queue | • JTIQ portfolio | MISO and SPP 2022 |
| **NorthernGrid** | Economic Study Request: Offshore Wind in Oregon | • Conceptual I-5 corridor connectivity improvements<br>• Conceptual 500 kV loop solution | NorthernGrid 2023 |
| **NYISO** | 2021–2040 System & Resource Outlook | • Public Policy transmission projects<br>• Road to 2040 policy case projects | NYISO 2022a |

[61] Neither the NERC Electricity Supply and Demand database (NERC 2022c) nor the long-term transmission plans considered here make up an exhaustive list of all transmission projects currently in development. Values presented are estimates based on readily available data.



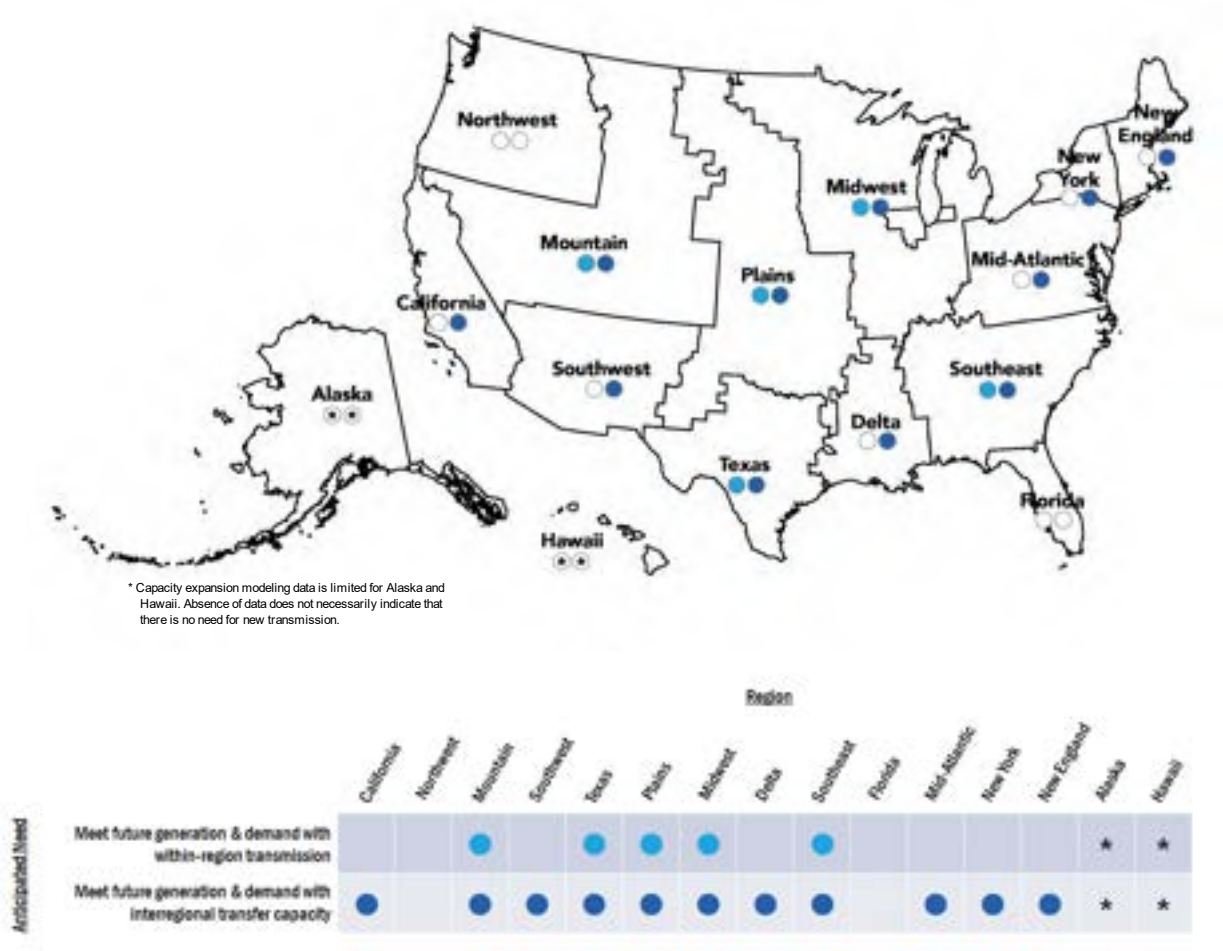




*Sources: Utility plan data includes all projects that have been completed, delayed, planned, and under construction above 100 kV from North American Electric Reliability Corporation (NERC 2022c). Long-term plan data from California Independent System Operator (CAISO 2022b), Electric Reliability Council of Texas, Inc (ERCOT 2022b), ISO New England (ISO-NE 2022b), (ISO-NE 2023), Midcontinent Independent System Operator (MISO 2022a), (MISO 2022b), MISO and Southwest Power Pool (MISO and SPP 2022), NorthernGrid (NorthernGrid 2023), and New York Independent System Operator (NYISO 2022a).*

***Figure VI-11. Comparison of utility transmission development plans with interquartile range of capacity expansion modeling results for the Moderate/High (top) and High/High (bottom) scenario groups in 2035.***

# VI.f. Conclusions and Summary of Future Needs Identified through Capacity Expansion Model Analysis

Figure VI-12 summarizes findings of anticipated transmission needs by geographic region as determined by the Section VI national capacity expansion modeling results analysis. The different color circles located on the map of Figure VI-12 (top) correspond with the transmission needs listed in the dashboard (bottom).




*Source: See the Supplemental Material for supporting references and methodology.*

*Note: Transmission need identified for geographic regions with Moderate/High scenario within-region or interregional transmission growth >50% in 2035 relative to 2020 levels.*

***Figure VI-12. Summary of future transmission needs identified in Section VI Moderate/High scenario group analysis by geographic region.***

**Increased transmission deployment helps regions meet growing demand needs reliably and cost effectively by connecting supply to demand.** Increased transfer capacities between regions enables regions to share electricity effectively, improving system reliability and resilience and providing access to low-cost clean energy that may be generated far from load centers (Brinkman et al. 2021; Brown and Botterud 2020). Several different generation technologies will contribute to meeting the Nation's growing electricity and clean energy

demands. Which generation technologies are built, and where, will be driven by market changes, policy decisions, and social and geopolitical concerns. The analysis of capacity expansion modeling work presented in this Needs Study shows that all combinations of new generation will require increased transmission deployment to remove expected constraints and congestion that would negatively impact consumers and bring new generation to market, but to differing degrees. Capacity expansion modeling studies help quantify the range of new transmission needed to meet future demand.

**Capacity expansion modeling shows within-region transmission capacity-mile deployment across all contiguous U.S. regions needs to increase 14% by 2030 and 24% by 2040 (median results) to meet a future with moderate load and clean energy growth.** The future power system described by this scenario group has less load and clean energy growth than that projected to be enabled by state and federal laws enacted since 2021. Regions in greatest need of cost-effective transmission growth are those in the middle of the country, including the Texas, Mountain, Plains, and Midwest regions.

**Interregional transfer capacity needs under these moderate scenario conditions are similar, needing to grow 14% by 2030 (median 16 GW) and 34% by 2040 (median 38 GW) nationally.** Increased transfer capacity among neighbors in the Eastern Interconnection show that cost savings and reliability benefits can be realized for regions sharing electricity, even in moderate growth futures.

**In future scenarios with moderate load but high clean energy assumptions—in line with the future power sector enabled by all currently enacted laws, including the IIJA and the IRA—both transmission deployment and transfer capacities need to increase nationwide.** In these moderate load and high clean energy growth futures enabled by the IIJA and IRA, median model results suggest **54,500 GW-mi of new within-region transmission will be needed nationwide by 2035** to meet the scenario conditions of this group, a 64% increase from today's transmission system. Regions in greatest need of transmission growth are the Southeast, Texas, Plains, and Midwest.

**Total median interregional transfer capacities across the contiguous United States are nearly 125 GW for scenarios with moderate load and high clean energy growth assumptions**, a fivefold increase from scenarios with similar load assumptions but lower clean energy growth assumptions. Several regions would benefit from increased connectivity with their neighbors as clean energy deployment increases to over 80% annual generation. Studies show a large growth in transfer capacity between all regions adjacent to the Plains, including across the three interconnections. Large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through increased transmission is shown to be cost-effective for neighboring regions.

**The need for transmission growth is even greater in future scenarios that have both high load and high clean energy assumptions.** The range of deployment results in this scenario group is also large, highlighting that the mix of generation and power sector technologies that enable both high load and clean energy growth vary significantly in their needs for additional transmission support. In 2030, median results suggest 33,200 GW-mi of new within-region transmission—a nearly 40% increase of today's system—is needed to meet the demands of

these scenarios. By 2040, new within-region transmission deployment need is projected to be 123,000 GW-mi (median), nearly one and a half times the size of today's transmission system. The value in sharing energy on an interregional basis continues to increase in future scenarios with high demand and clean energy growth. Median study results anticipate new interregional transfer capacity needs of 152 GW in 2030 (139% growth compared to today's system) and 510 GW in 2040 (467% growth) nationwide.

# VII. Process for Preparing the 2023 National Transmission Needs Study

This section reviews the process the Department followed to prepare the 2023 National Transmission Needs Study. It describes the Department's consultation with states, Tribes, and regional entities pursuant to Section 216(a) of the FPA.

As directed by the FPA, the Department consulted with states, Tribes, and regional entities in preparing this study from July through November 2022. Consultation took the form of circulating a notification letter to give entities at least 30 days' notice that the "consultation draft" would be sent to them for review and feedback, then subsequently distributing the consultation draft of the National Transmission Needs Study to each state (including points of contact from state energy offices, governors' offices, utility commissions chairs, and state public utility commission groups for multistate RTOs/ISOs), Tribes, and regional entities (including transmission reliability and planning entities) in the United States, along with an invitation to provide written comment on the draft or to meet with DOE staff, in person or by phone, to convey comments. In addition, DOE briefed the states, Tribes, and regional entities via a series of six webinars on the consultation draft, with one webinar open to all consultation draft recipients and the other five targeted at each entity type in partnership with a convening group to help with amplification of the webinar (e.g., DOE partnered with the National Association of State Energy Offices for the webinar targeted at state energy offices). Appendix A-1 of the public draft of this Needs Study[62] contains a list of 20 entities that submitted written or verbal comments on the consultation draft of the study, and an overview summary of the comments received.

The Department made substantial revisions based on consultation comments ahead of releasing an updated Draft for Public Comment in February 2023. Appendix A-2 of the public draft contains a detailed comment matrix that documents each individual comment received and the manner in which the Department resolved each comment. Department staff held a public webinar, which accompanied the public draft in March 2023. A 9-week public comment period was open from February to April 2023. Departmental staff met with all commenting entities who requested an audience to discuss their comments in greater detail. Table VII-1 lists the 58 entities who submitted public comments. A compilation of received public comments is available online.[63] This Final National Transmission Needs Study reflects changes DOE made in response to public comments. A summary of the comments received during the public comment period and the Department's resolution can be found in Appendix B.

[62] DOE. 2023. National Transmission Needs Study: Draft for Public Comment. Feb. 2023. Available at https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[63] DOE. 2023. Comments – National Transmission Needs Study Public Draft – Spring 2023. Available at: https://www.energy.gov/sites/default/files/2023-07/072423_Needs-Study_Public-Draft-Comments-Compiled_Spring-2023.pdf.

***Table VII-1. List of commenting entities.***

| Commenting Entities | | |
|---|---|---|
| Advanced Energy Group | Data Center Coalition | National Grid |
| Advanced Energy United | DataCapable | National Hydropower Association |
| AES Corporation | Econwerks LLC | New Jersey Board of Public Utilities |
| Alaska Energy Authority | Edison Electric Institute | New York Transmission Owners |
| Alliant Energy | Electric Reliability Council of Texas | North Carolina Utilities Commission |
| American Chemistry Council | Environmental Defense Fund | Northern California Tribal Chairpersons Association |
| American Clean Power Association | Federation of American Scientists | PJM Interconnection |
| American Council on Renewable Energy | Gallatin Power | Public Services Enterprise Group Inc. |
| American Electric Power Service Corporation | Grid United | Seattle City Light |
| Americans for a Clean Energy Grid | Hydro-Québec | Southeast Public Interest Groups |
| Arizona Municipal Power Users' Association and Irrigation and Electrical Districts Association of Arizona | International Transmission Company Holdings Corporation | Southern Renewable Energy Association |
| Association for Modern Powerlines | ISO New England Inc. | Sponsors of the Southeastern Regional Transmission Planning Process |
| Avangrid | Janice Cooper | Transmission Developers Inc New England |
| Blue Lake Rancheria Tribe | Juneau Hydropower | Utah Public Lands Coordinating Office |
| Center for Biological Diversity | Keryn Newman | Vijayasekar Rajsekar |
| Clean Energy Buyers Association | LineVision | Western Electricity Coordinating Council |
| Columbia River Treaty Power Group | Martyn Roetter | William Driscoll |
| Con Edison | Monitoring Analytics | Working for Advanced Transmission Technologies Coalition |
| Dana Siler | National Electrical Manufacturers Association | Xcel Energy |
| (Filed jointly) Natural Resources Defense Council, Sustainable FERC Project, RMI, Earthjustice, Sierra Club, National Wildlife Federation, Southern Environmental Law Center, Western Resource Advocates, Montana Environmental Information Center, National Audubon Society, and Alliance for Affordable Energy | | |

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# Appendix A: National and Regional Fact Sheets

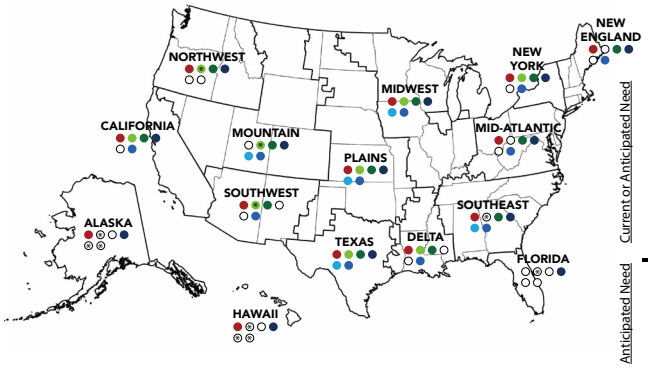
GRID DEPLOYMENT OFFICE

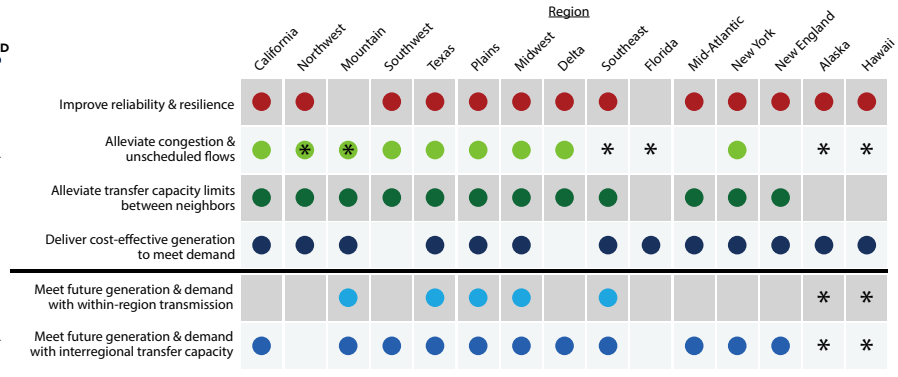
FACT SHEET

# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# UNITED STATES

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs across the United States. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




**Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO)regions and capacity expansion modeling data is limited for Alaska and Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.*

## FINDINGS OF TRANSMISSION NEED ACROSS THE UNITED STATES

- **Improve reliability and resilience.** **Nearly all regions** in the United States would gain improved reliability and resilience from additional transmission investments. Some regions have acute reliability and resilience needs that additional transmission deployment can address.
- **Alleviate congestion and unscheduled flows.** Regions with historically high levels of within-region congestion—the **Northwest, Mountain, Texas, and New York** regions in particular—as well as regions with unscheduled flows that pose reliability risks—**California, Northwest, Mountain, and Southwest** regions—need additional, strategically placed transmission deployment to reduce this congestion.
- **Alleviate transfer capacity limits between regions.** Historically, the data assessed show a need for transmission to alleviate transmission constraints that prevent moving electricity across the interconnection seams—**between the Mountain and Plains** regions and **between Texas and all its neighbors** (Southwest, Plains, and Delta regions). Similar needs are also found **between the Plains and the Midwest and Delta** regions, the Plains region's two eastern neighbors.
- **Deliver cost-effective generation to meet demand.** Areas of several regions endure consistently high prices, most notably in **New York, California, and the Plains, Midwest, and Mid-Atlantic regions**. Additional transmission to bring cost-effective generation to demand in these high-priced locations would help lower prices.
- **Meet future generation and demand with additional within-region transmission.** The clean energy transformation, evolving regional demand, and increasingly extreme events must all be accommodated by the future power grid. Significant transmission deployment is needed as soon as 2030 in the **Plains, Midwest, and Texas** regions. By 2040, large deployments will also be needed in the **Mountain, Mid-Atlantic, and Southeast regions**.
- **Meet future generation and demand with additional interregional transmission transfer capacity.** The same power sector characteristics are also driving increased need in interregional transmission deployment. By 2040, there will be a significant need for new interregional transmission between **nearly all regions**.

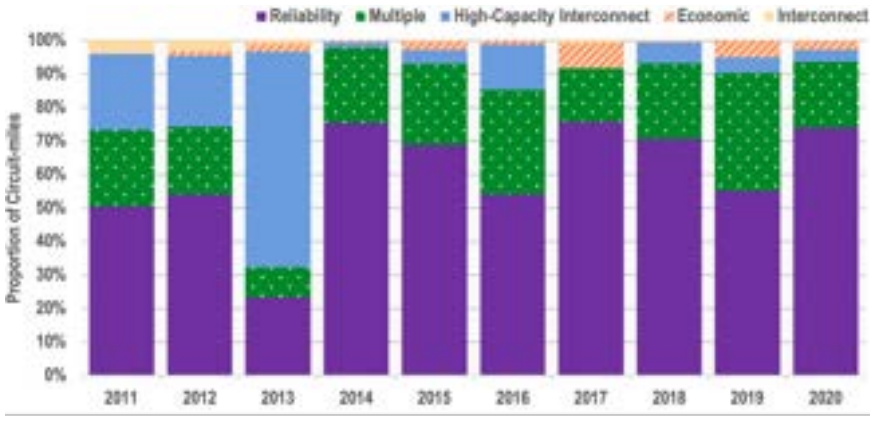
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Proportion of national circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




The proportion of overall transmission circuit-miles installed to address specific **system reliability needs** has grown with time, from 44% in 2011 to 74% in 2020.

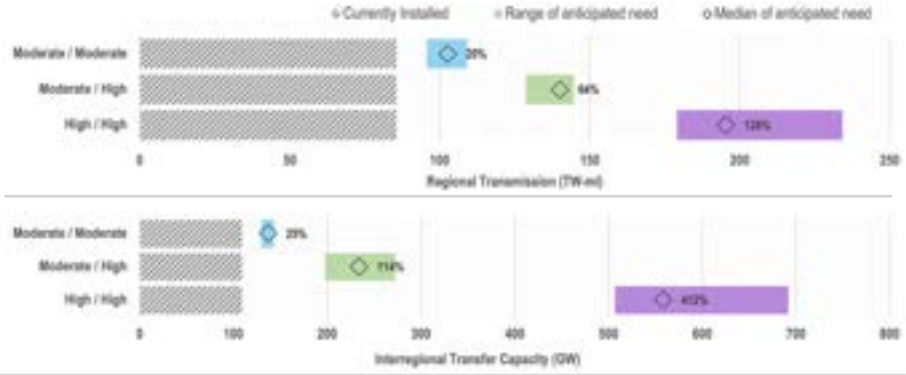
Wholesale market price differentials demonstrate that are the **highest value of new interregional transmission** exists **across the three electrical interconnections**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need across the United States in 2035**

Anticipated need for three future scenario groups labeled as __ load / __ clean energy growth. Median % growth compared to 2020 system shown.




There is an **increasing need for both within-region and interregional transfer capacity by 2035** as consumer load and clean energy generation grows nationwide. These needs also grow with time.

Median 2035 capacity expansion modeling results for each scenario group from the Needs Study highlighted.

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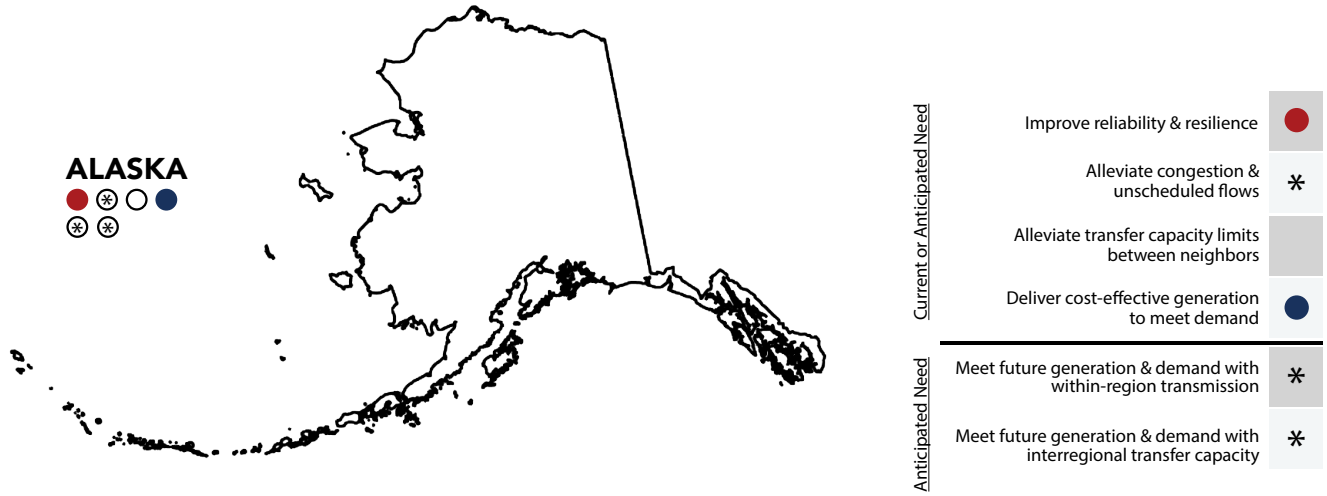
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# ALASKA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Alaska. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




**Wholesale market price data is limited for non-Regional Transmission Organization/Independent System Operator regions, and capacity expansion modeling data is limited for Alaska. Absence of data does not necessarily indicate that there is no need for new transmission.*

## FINDINGS OF TRANSMISSION NEED IN ALASKA

› **Improve reliability and resilience.** Anticipated generation retirements in Alaska's northern Railbelt region are expected to require capacity replacement from power purchase agreements with southcentral Railbelt utilities and new renewable resources installations. Transmission upgrades to deliver needed capacity to the northern Railbelt region would reduce existing capacity constraints negatively impacting the Alaska Intertie. Similarly, planned generation capacity increases on the Kenai Peninsula in the southern Railbelt region are anticipated to require transmission upgrades to reduce constraints and increase capacity exports on the Kenai Intertie. Further, deployment of additional transmission paths parallel to constrained single transmission lines—particularly near the interties and certain areas of the southcentral Railbelt region—would help reduce the need for load shedding following contingency events.

› **Deliver cost-effective generation to meet demand.** Outside of the Railbelt service region, rural Alaskan communities are served largely by standalone microgrids. Additional transmission between isolated Alaskan communities served by rural utilities, as well as increased rural utility interconnection with the Railbelt transmission system where feasible, would help accommodate higher levels of renewable capacity and help supply cost-effective generation in areas that rely on higher-cost, imported diesel fuel.

**HELPFUL LINKS**

› **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

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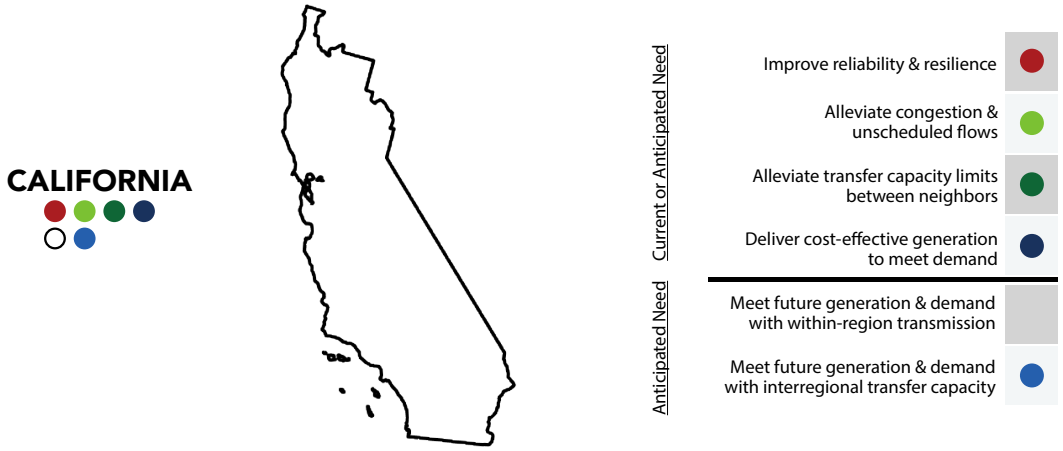
FACT SHEET

# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# CALIFORNIA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of California. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN CALIFORNIA

- **Improve reliability and resilience.** California faces risk of load curtailment during extreme weather events, wildfires, and earthquakes, particularly as the region becomes increasingly reliant on variable energy resources and energy imports to meet peak demand. Additional transmission upgrades would reduce risks to electricity reliability from extreme events. Further, California is anticipated to experience reserve margin shortfalls in the next few years, and additional transmission capacity would accommodate new and diverse resource integration and anticipated generation retirements.
- **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 66, located at the intersection of the Northwest, California, and Mountain regions; additional transmission deployment would alleviate these unscheduled flows.
- **Alleviate transfer capacity limits between California and its neighbors.** High congestion value of interregional transmission from 2012 through 2020 exists between California and the Mountain regions, with an average marginal value of transmission equal to $14/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in northern and southern coastal areas, and additional transmission to bring cost-effective generation to demand would help reduce these prices. California is also anticipated to require higher levels of new generation and demand resources aligned with state laws, including out-of-state wind and solar generation, and additional transmission capacity would help accommodate the necessary resources.
- **Meet future generation and demand with additional interregional transfer capacity.** California would need an anticipated 1.5 to 2.3 GW of additional transfer capacity with the Mountain region in 2035 (median of 1.9 GW, an 88% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between California and the Southwest (median value of 0.3 GW) and Northwest (median value of 0.1 GW) regions may also be required.

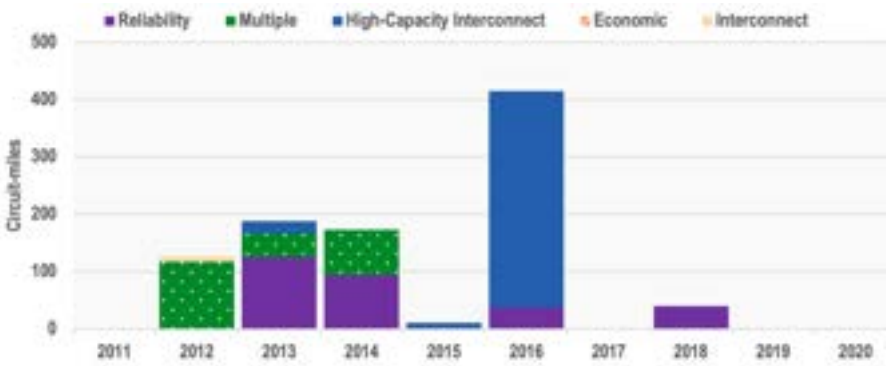
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in California were installed to **address a diversity of concerns**. Projects installed in **2016 were largely high-capacity** (> 230 kV) projects to interconnect generation.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between California and the Mountain region**.

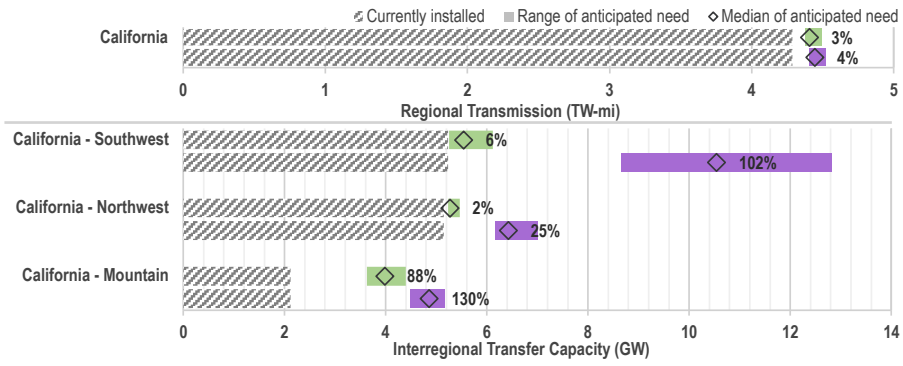
The average marginal value of transmission between California and the Mountain region from 2012 through 2020 is equal to $14/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for California in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.12 TW-miles of new within-region transmission by 2035** (3% growth relative to 2020) and **1.9 GW of new interregional transfer capacity with the Mountain region by 2035** (88% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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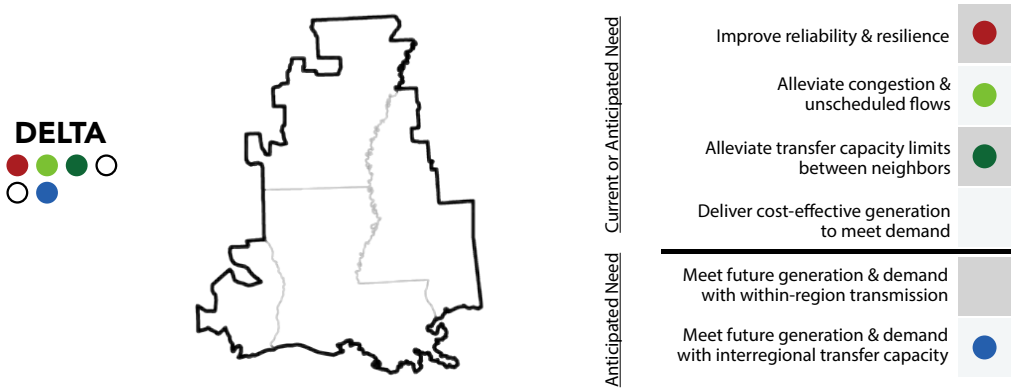
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# DELTA REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Delta region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN THE DELTA REGION

- **Improve reliability and resilience.** Generation retirements over the next few years are anticipated to result in capacity shortfalls without additional generation or import transfer capability additions. Additional regional or interregional transmission to access diverse generation resources would help ensure resource adequacy. Additional interregional transfer capacity would also bolster system resilience and mitigate load shedding during extreme weather events, as was experienced during winter storms in both 2018 and 2021. The Delta region is also susceptible to increasingly severe hurricane storm surges, which can damage transmission facilities and result in power outages.
- **Alleviate congestion and unscheduled flows.** Congestion costs in the combined Midwest and Delta regions have increased in recent years due to insufficient transmission to support wind generation and due to generation and transmission outages, including the recent impact of Hurricane Laura in the Delta region.
- **Alleviate transfer capacity limits between the Delta region and its neighbors.** High congestion value of interregional transmission from 2012 through 2020 exists between the Delta region and Texas, with an average marginal value of transmission equal to $16/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Delta region will need between 10.8 and 23.8 GW of additional transfer capacity with the Plains region in 2035 (median of 19.7 GW, a 414% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between the Delta and Southeast regions (median value of 5.1 GW) may also be required.

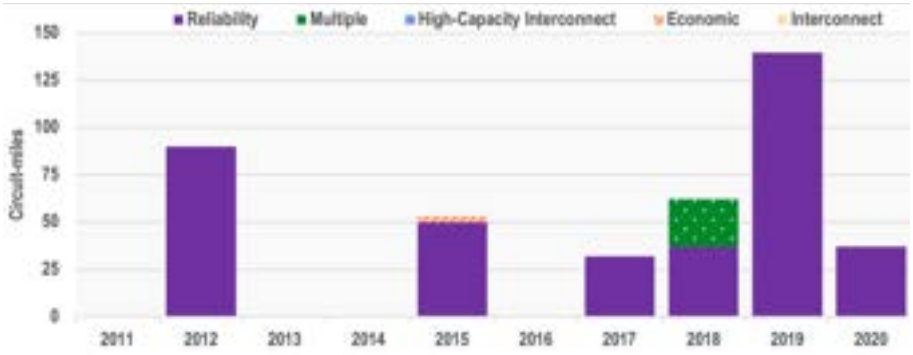
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in the Delta region were predominantly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

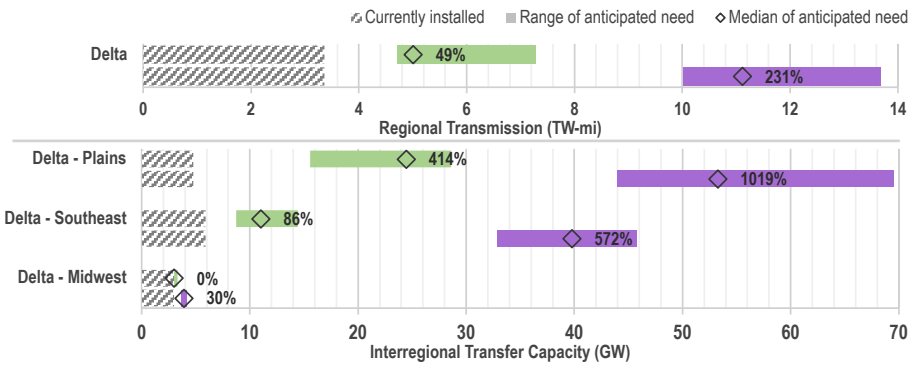
Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between the Delta region and Texas**.

The average marginal value of transmission between the Delta region and Texas from 2012 through 2020 is equal to $16/MWh.

**Within-region transmission and interregional transfer capacity need for the Delta region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **1.7 TW-miles of new within-region transmission by 2035** (49% growth relative to 2020) and **19.7 GW of new interregional transfer capacity with the Plains region by 2035** (414% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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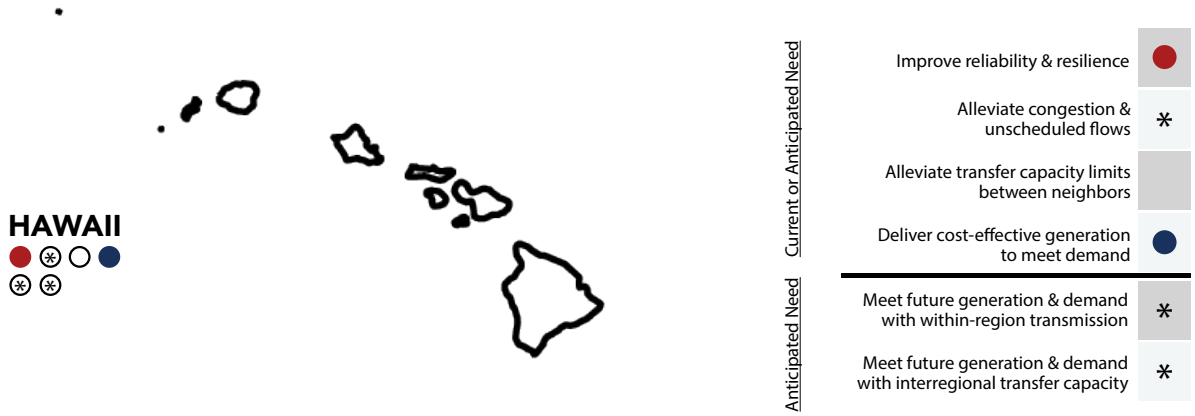
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# HAWAII

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Hawaii. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




** Wholesale market price data is limited for non-Regional Transmission Organization/Independent System Operator regions and capacity expansion modeling data is limited for Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.*

## FINDINGS OF TRANSMISSION NEED IN HAWAII

› **Improve reliability and resilience.** Transmission systems on Hawaii, Lanai, Maui, Molokai, and Oahu islands are approaching capacity limitations and will require additional transmission capacity as the islands continue to integrate renewable resources through ongoing and future procurement necessary to meet state clean energy goals. Hawaii anticipates potential reliability concerns due to high levels of inverter-based renewables integration. In Kauai, system operators note the transmission system is capable of riding through a single contingency in accordance with its system voltage and frequency requirements with current generation and load levels; however, with anticipated load growth, additional transmission infrastructure would allow for a more resilient grid in the face of plausible contingency scenarios.

› **Deliver cost-effective generation to meet demand.** Transmission network expansion is critical for Hawaii, Lanai, Maui, Molokai, and Oahu islands to integrate sufficient renewable resources required for the state to reach its 100% renewable by 2045 renewable portfolio standard target.

### HELPFUL LINKS

› **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

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FACT SHEET

# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# MID-ATLANTIC REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Mid-Atlantic. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.

## FINDINGS OF TRANSMISSION NEED IN THE MID-ATLANTIC REGION

- **Improve reliability and resilience.** Reliability risks are anticipated to arise in the near term due to electricity demand growth, thermal generator retirements, and increases in intermittent and limited-duration resource interconnection requests. Additional transmission additions and upgrades in the near term would help maintain resource adequacy and accommodate generation loss. Additionally, stronger transmission ties with neighboring regions would help support reliability and resilience of the Mid-Atlantic system during extreme weather events, such as the 2018 bomb cyclone and 2020 Winter Storm Elliott events.
- **Alleviate transfer capacity limits between the Mid-Atlantic region and New York.** High congestion value of interregional transmission from 2012 through 2020 exists between the Mid-Atlantic region and New York, with an average marginal value of transmission equal to $18/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in eastern Maryland, eastern Virginia, and both Maryland and Delaware portions of the Delmarva Peninsula; additional transmission to bring cost-effective generation to demand would help reduce these prices.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Mid-Atlantic region will need between 28 and 51.7 GW of additional transfer capacity with the Midwest in 2035 (median of 33.8 GW, a 156% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between the Mid-Atlantic and the Southeast (median value of 6.9 GW) and New York (median value of 2.4 GW) may also be required.

### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.

Transmission projects energized over the last decade in the Mid-Atlantic region were predominantly installed to **address reliability concerns**.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between the Mid-Atlantic region and New York**.

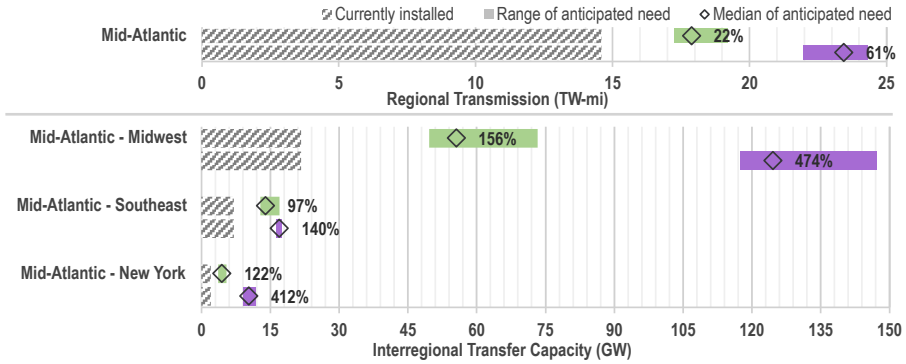
The average marginal value of transmission between the Mid-Atlantic region and New York from 2012 through 2020 is equal to $18/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Mid-Atlantic in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **3.3 TW-miles of new within-region transmission by 2035** (22% growth relative to 2020) and **33.8 GW of new interregional transfer capacity with the Midwest region by 2035** (156% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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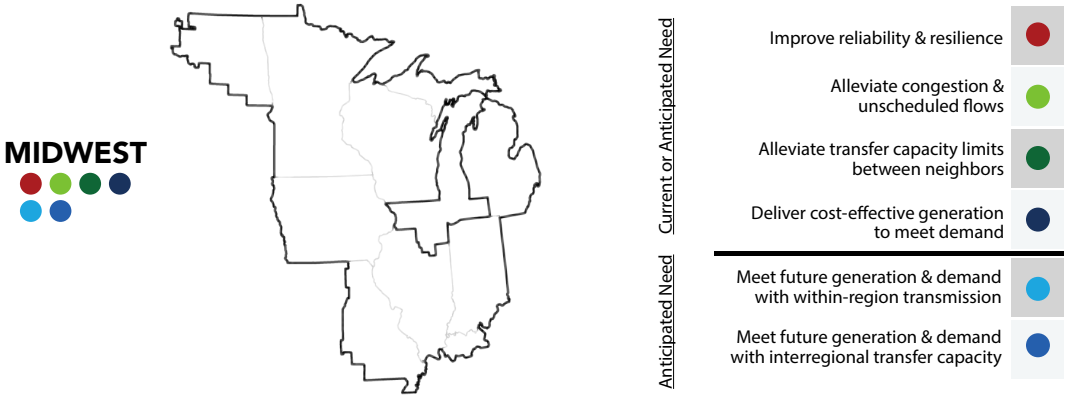
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# MIDWEST REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Midwest region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN THE MIDWEST REGION

- **Improve reliability and resilience.** Generation retirements over the next few years are anticipated to result in capacity shortfalls without additional generation or import transfer capability additions. Additional regional or interregional transmission to access diverse generation resources would help ensure resource adequacy in the region. Additional interregional transfer capacity would also bolster system resilience and mitigate load shedding during extreme weather events, as was experienced during winter storms in both 2018 and 2021.
- **Alleviate congestion and unscheduled flows.** Congestion costs in the combined Midwest and Delta regions have increased in recent years due to insufficient transmission to support wind generation and due to generation and transmission outages.
- **Alleviate transfer capacity limits between the Midwest region and its neighbors.** High congestion value of interregional transmission from 2012 through 2020 exists between the Midwest region and New York, with an average marginal value of transmission equal to $17/MWh. Similarly high congestion values of transmission exist between the Midwest and Plains regions, ranging from $4/MWh to $15/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas in northwestern Wisconsin and in eastern and the Upper Peninsula of Michigan persist, and additional transmission to bring cost-effective generation resources to demand would help these areas reduce prices.
- **Meet future generation and demand with additional within-region transmission.** The Midwest region will need an anticipated 10 to 14.9 TW-miles of additional within-region transmission in 2035 (median 13.3 TW-miles, a 112% increase relative to the 2020 system) to meet moderate load and high clean energy growth scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** The Midwest region will need an anticipated 28 to 51.7 GW of additional transfer capacity with the Mid-Atlantic region in 2035 (median of 33.8 GW, a 156% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Midwest and the Plains (median value of 21.1 GW) and Southeast (median value of 4.5 GW) regions may also be required.

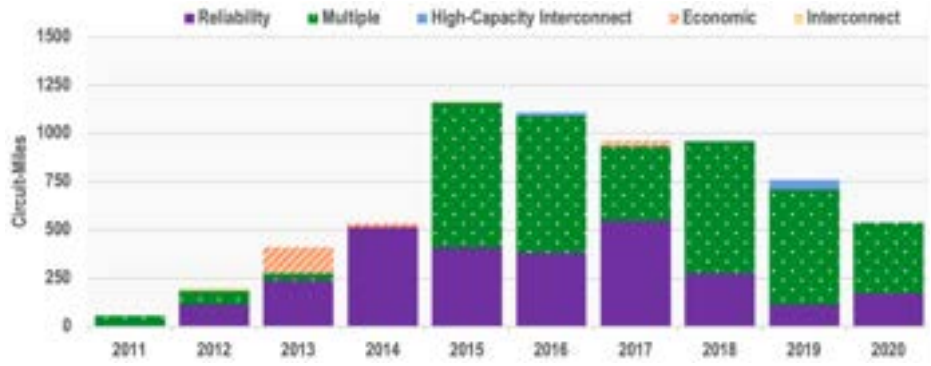
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011and 2020 by project driver.




Transmission projects energized over the last decade in the Midwest region **addressed a diverse set of needs**, including **reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

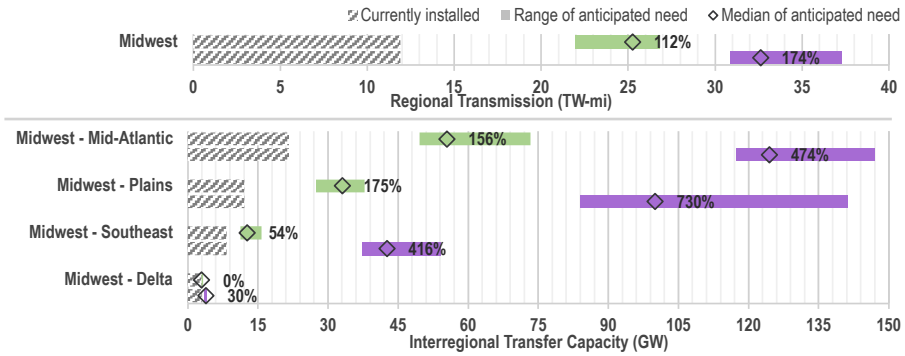
Wholesale market price differentials demonstrate that the **highest value of new interregional transmission** exists **between the Midwest region and New York**.

The average marginal value of transmission between the Midwest region and New York from 2012 through 2020 is equal to $17/MWh.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Midwest region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **13.3 TW-miles of new within-region transmission by 2035** (112% growth relative to 2020), and **33.8 GW of new interregional transfer capacity with the Mid-Atlantic region by 2035** (156% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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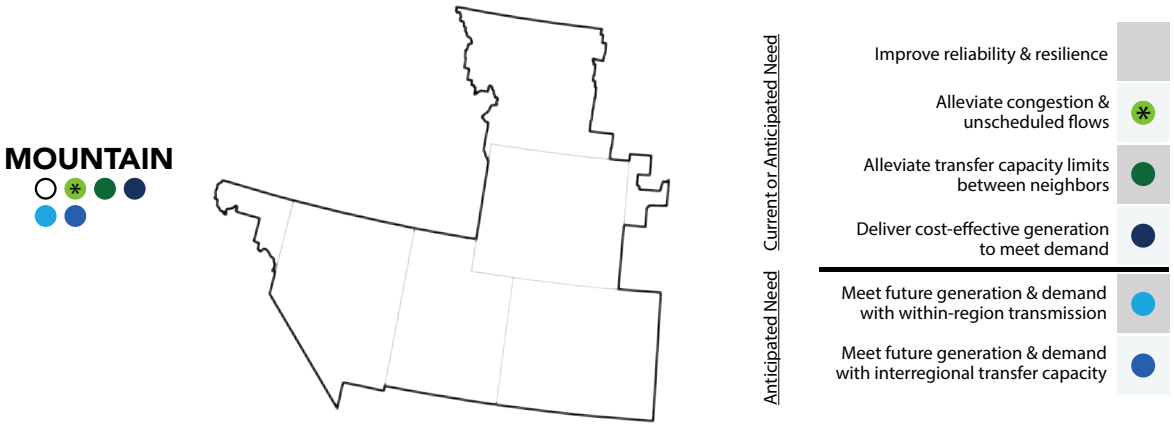
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# MOUNTAIN REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Mountain region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




**Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO region.*

## FINDINGS OF TRANSMISSION NEED IN THE MOUNTAIN REGION

- **Alleviate congestion and unscheduled flows.** Unscheduled flows in the Mountain region persist, specifically along Colorado's western, southern, and northern borders, and high congestion values exist within the Mountain region. Additional transmission deployment would help alleviate these needs.
- **Alleviate transfer capacity limits between the Mountain region and its neighbor.** High congestion value of interregional transmission from 2012 through 2020 exists between the Mountain and Plains regions, ranging from $8/MWh to $21/MWh. Similarly high congestion values of transmission exist between the Mountain and California ($14/MWh) and Northwest ($14/MWh) regions. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** Generation interconnection queues within the Mountain region contain a high number of clean generation projects, and county- and state-level renewable energy goals are anticipated to drive future renewable resource development. Transmission buildout would help to accommodate cost-effective resource integration.
- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Mountain region will need between 2.5 and 4.5 TW-miles of within-region transmission in 2035 (median 3.1 TW-miles, a 90% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** The Mountain region will need an anticipated 2.7 to 4.4 GW of additional transfer capacity with the Northwest region in 2035 (median of 3.3 GW, a 26% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Mountain and the Southwest (median value of 1.7 GW), California (median value of 1.9 GW), and the Plains (median value of 2.6 GW) regions may also be required.

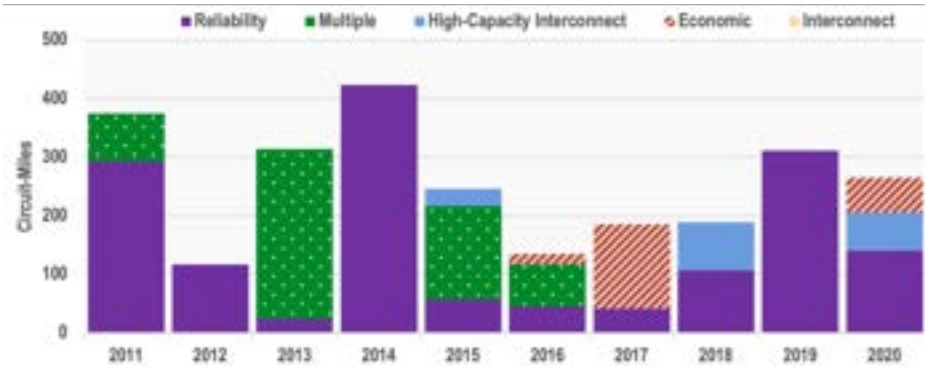
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in the Mountain region **addressed a diversity of needs**, including **reliability** concerns and to specifically realize **production cost savings**.

Wholesale market price differentials demonstrate that the **highest value of new interregional transmission** exists **between the Mountain and Plains regions**.

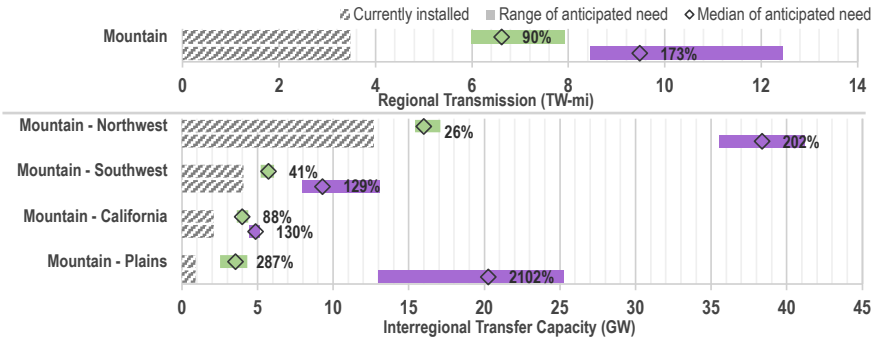
The average marginal value of transmission between the Mountain and Plains regions from 2012 through 2020 is equal to $15/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Mountain region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **3.1 TW miles of new within-region transmission by 2035** (90% growth relative to 2020) and **3.3 GW of new interregional transfer capacity with the Northwest region by 2035** (26% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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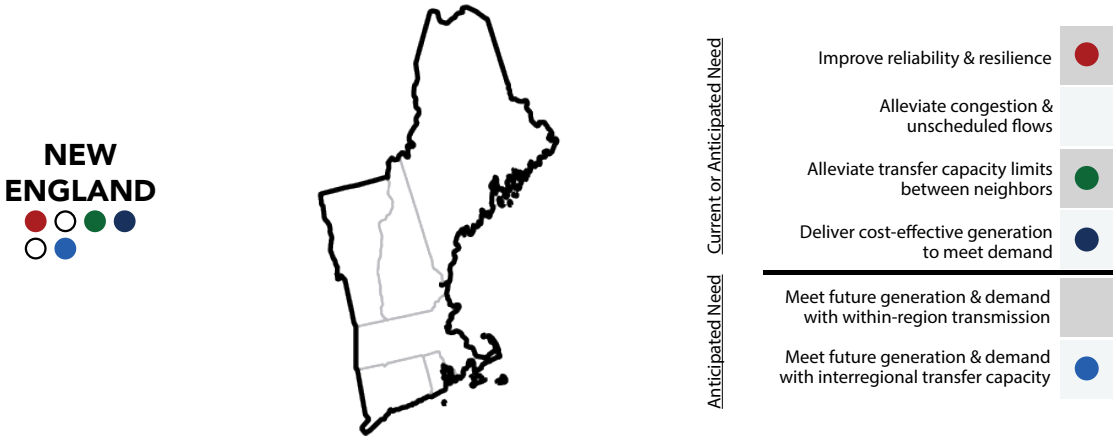
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# NEW ENGLAND

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of New England. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN NEW ENGLAND

- **Improve reliability and resilience.** Resource adequacy will be harder to maintain in a future where load is served by only variable energy resources. A robust transmission system is needed to access a diverse generation mix throughout the region. Increased interregional transmission provides resilience and consumer savings during extreme weather events, as experienced by the Northeast in the January 2018 bomb cyclone event.
- **Alleviate transfer capacity limits between New England and New York.** The highest congestion value of interregional transmission in the Eastern Interconnection from 2012 through 2020 exists between New England and New York, with an average marginal value of transmission ranging from $16 to $21/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** Increased interregional transmission provides resilience and consumer savings, as experienced by the Northeast in the January 2018 bomb cyclone event.
- **Meet future generation and demand with additional interregional transfer capacity.** New England will need an estimated 3.4 to 6.3 GW of additional transfer capacity with New York in 2035 (median of 5.2 GW, a 255% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.

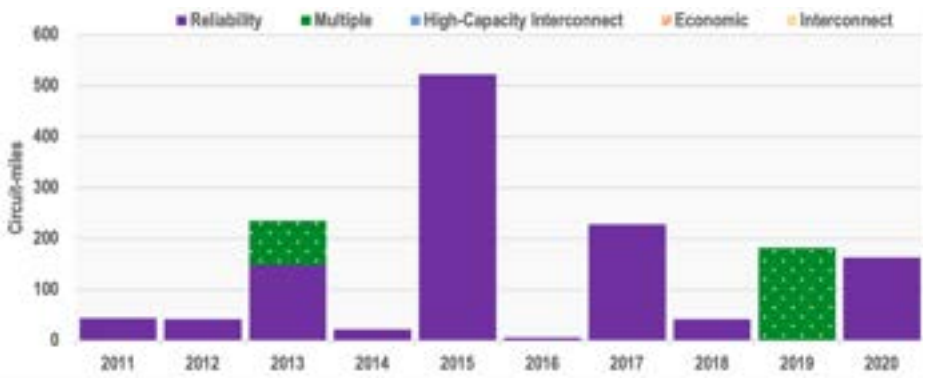
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in New England were predominantly installed to **address reliability concerns**, and occasionally to address multiple drivers.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

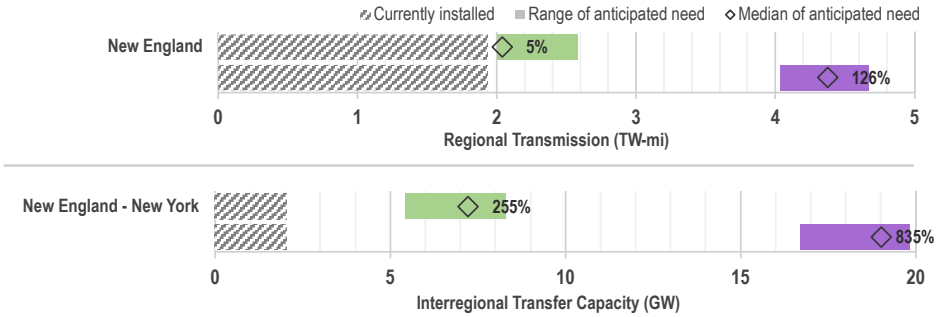
Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between New England and New York**.

The average marginal value of transmission between New England and New York from 2012 through 2020 is equal to $19/MWh.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for New England in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.1 TW-mi of new within-region transmission by 2035** (5% growth relative to 2020) and **5.2 GW of new interregional transfer capacity with New York by 2035** (255% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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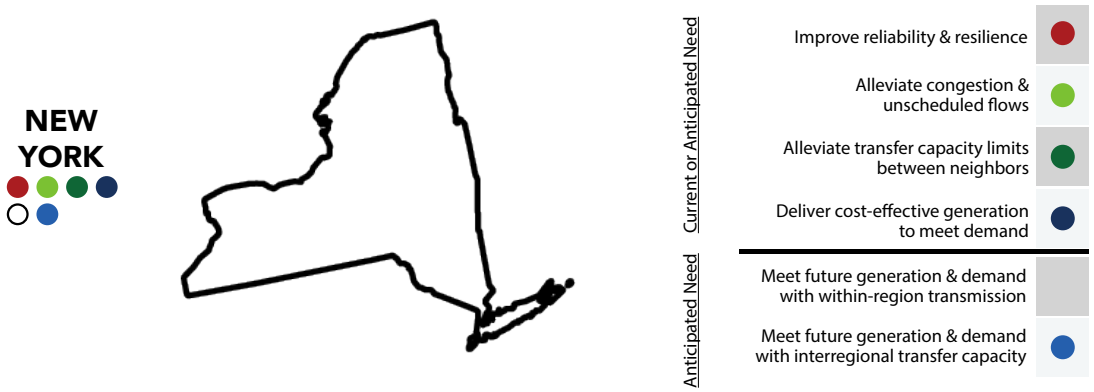
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# NEW YORK

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of New York. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN NEW YORK

› **Improve reliability and resilience.** Reliability risks are anticipated to increase during winter months by mid-2030 as the grid is becoming winter-peaking. Expanding transmission to access geographically diverse energy resources would reduce future resource adequacy risks. Increased interregional transmission provides resilience and consumer savings during extreme weather events, as experienced by New York in the January 2018 bomb cyclone event.

› **Alleviate congestion and unscheduled flows.** High congestion values exist within New York, indicating that additional transmission deployment would reduce system congestion and constraints. Long-term planning scenarios with a significant portion of renewable generation would exacerbate existing transmission congestion with a 23% increase statewide by 2030.

› **Alleviate transfer capacity limits between New York and its neighbors.** The highest congestion value of interregional transmission in the Eastern Interconnection from 2012 through 2020 exists between New York and New England, with an average marginal value of transmission ranging from $16 to $21/MWh. Similarly high congestion values exist between New York and the Mid-Atlantic ($18/MWh) and Midwest ($17/MWh) regions. A high congestion value indicates that transmission between the regions would reduce system congestion and constraints.

› **Deliver cost-effective generation to meet demand.** High-priced areas in Long Island persist, and additional transmission to bring cost-effective resources to demand would help reduce these prices.

› **Meet future generation and demand with additional interregional transfer capacity.** New York will need an anticipated 3.4 to 6.3 GW of additional transfer capacity with New England in 2035 (median of 5.2 GW, a 255% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between New York and the Mid-Atlantic region (median value of 2.4 GW) may also be required.

### HELPFUL LINKS

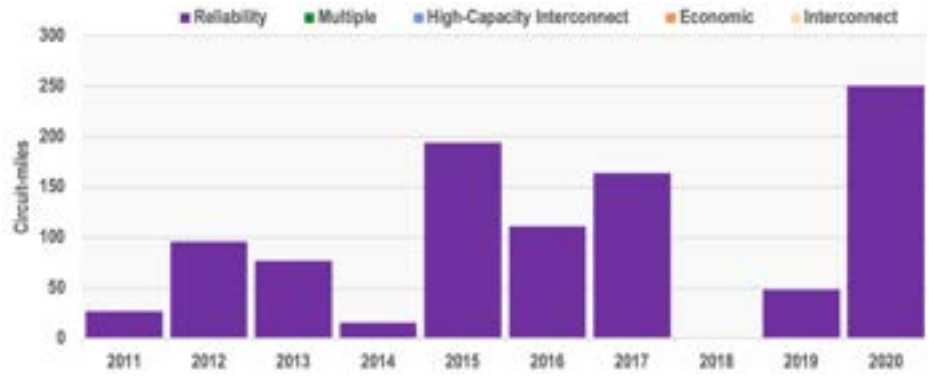
› **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines ( ≥100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in New York were installed exclusively to **address reliability concerns**.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between New York and New England**.

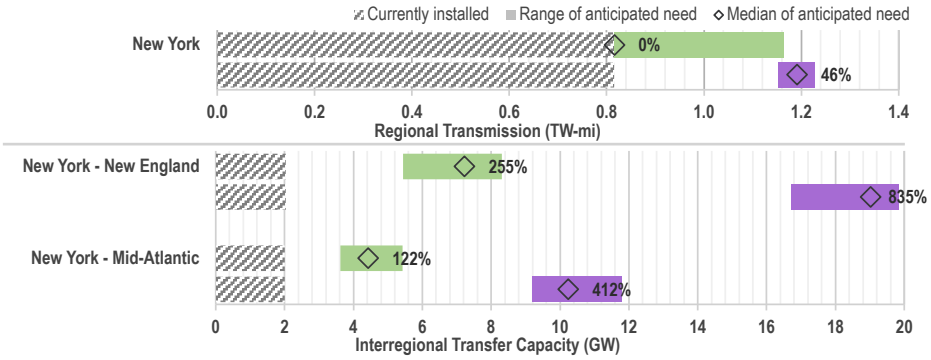
The average marginal value of transmission between New York and New England from 2012 through 2020 is equal to $19/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for New York in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **5.2 GW of new interregional transfer capacity with New England by 2035** (255% growth relative to 2020) and **2.4 GW with the Mid-Atlantic region by 2035** (122% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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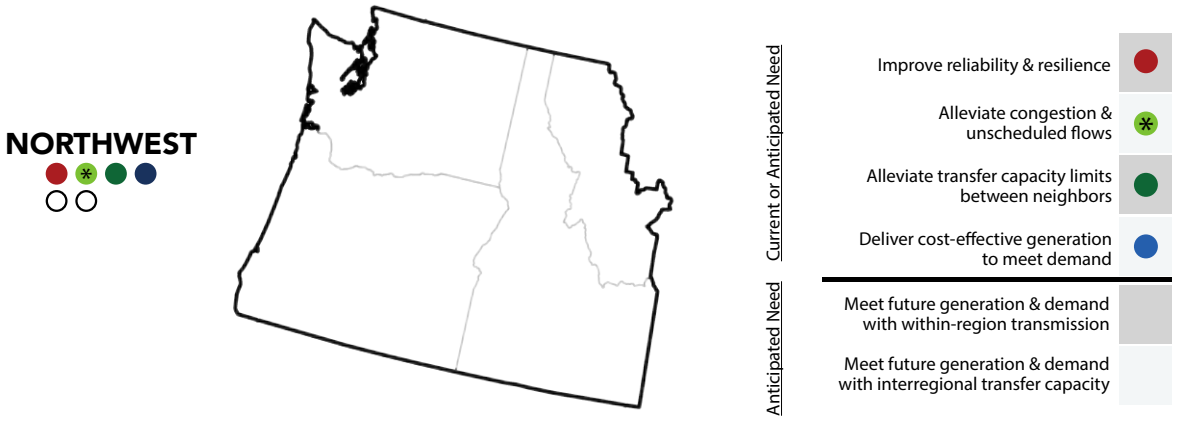
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# NORTHWEST REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Northwest region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




**Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

## FINDINGS OF TRANSMISSION NEED IN THE NORTHWEST REGION

- **Improve reliability and resilience.** The Northwest region faces risk of load curtailment during extreme weather events and wildfires, particularly as the region becomes increasingly reliant on variable energy resources to meet peak demand. Additional transmission upgrades would reduce risks to electricity reliability from extreme events.
- **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 66, located at the intersection of the Northwest, California, and Mountain regions, and high congestion values exist within the Northwest region. Additional transmission deployment would help alleviate these needs.
- **Alleviate transfer capacity limits between the Northwest and Mountain regions.** High congestion value of interregional transmission from 2012 through 2020 exists between the Northwest and Mountain regions, with an average marginal value of transmission equal to $14/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** The Northwest region is anticipated to integrate higher levels of new generation to meet state-level power sector emissions reduction targets. Additional interregional transmission would allow for an increase of cost-effective, out-of-state clean energy imports, as well as the export of low-cost clean energy from the Northwest region to other western states.

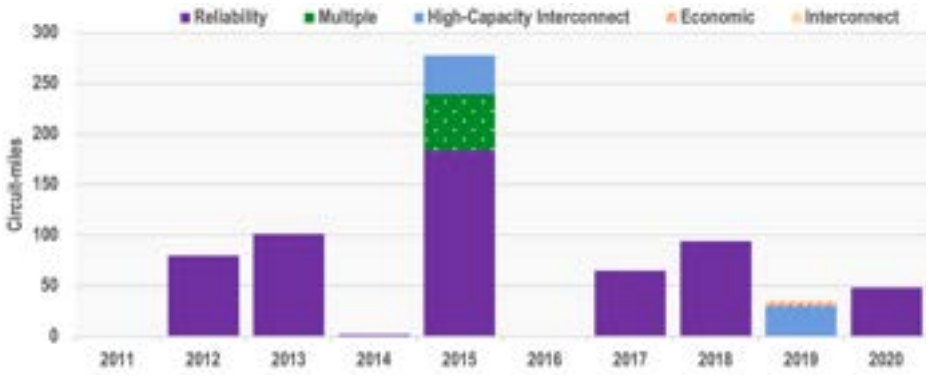
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in the Northwest region were predominantly installed to **address reliability concerns**.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between the Northwest and Mountain regions**.

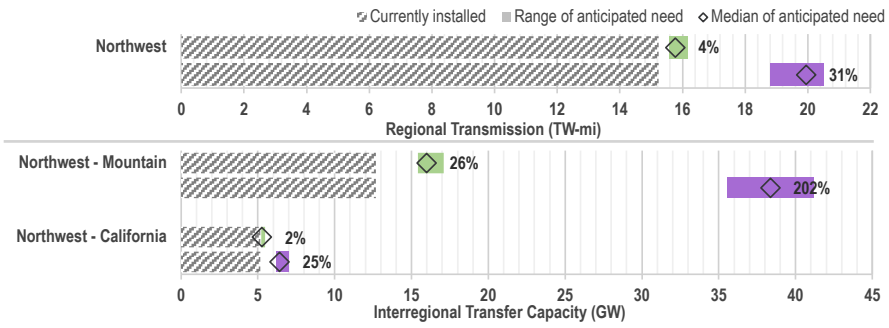
The average marginal value of transmission between the Northwest and Mountain regions from 2012 through 2020 is equal to $14/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Northwest region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.5 TW-miles of new within-region transmission by 2035** (4% growth relative to 2020) and **3.3 GW of new interregional transfer capacity with the Mountain region by 2035** (26% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# PLAINS REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Plains region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.

## FINDINGS OF TRANSMISSION NEED IN THE PLAINS REGION

- **Improve reliability and resilience.** The Plains region was unable to import additional generation capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities with neighboring regions would improve system reliability during extreme weather events.
- **Alleviate congestion and unscheduled flows.** In 2020, high wind generation output and transmission limitations generated high congestion costs in eastern Kansas, southwestern Missouri, and southeastern Oklahoma. Increased transmission capacity within the region would help increase transmission capability for wind-producing areas and reduce prices in congested areas.
- **Alleviate transfer capacity limits between the Plains region and its neighbors.** Highest congestion value of interregional transmission from 2012 through 2020 exists between the Plains region and Texas, ranging from $15/MWh to $69/MWh. High congestion values of transmission also exist between the Plains and Mountain ($8/MWh–$21/MWh) and Midwest ($4/MWh–$15/MWh) regions. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in southern Oklahoma and southwest Missouri, and additional transmission to bring cost-effective generation to demand would help these areas reduce prices.
- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Plains region will need between 7.3 and 9.9 TW-miles of within-region transmission in 2035 (median 8.3 TW-miles, a 119% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** The Plains region will need an anticipated 15.4 to 25.8 GW of additional transfer capacity with the Midwest region in 2035 (median of 21.1 GW, a 175% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller transfers between the Plains region and the Delta (median value of 19.7 GW), Texas (median value of 9.8 GW), Southwest (median value of 3.7 GW), and Mountain (median value of 2.6 GW) regions may also be required.

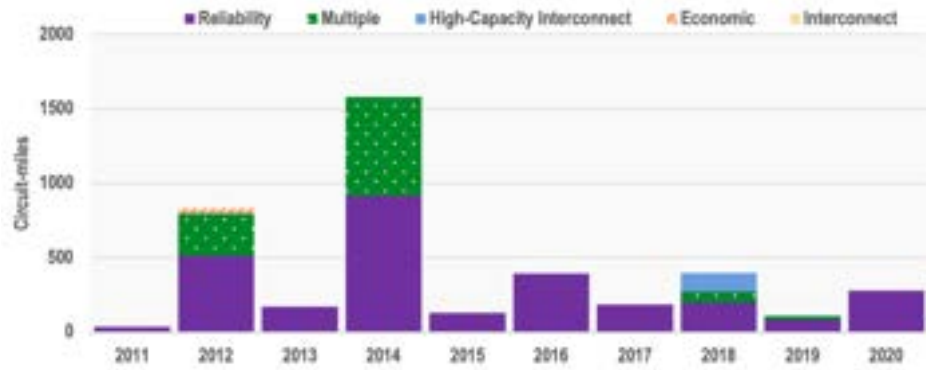
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines ( ≥100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in the Plains region were predominantly installed to **address reliability concerns**.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between the Plains region and Texas**.

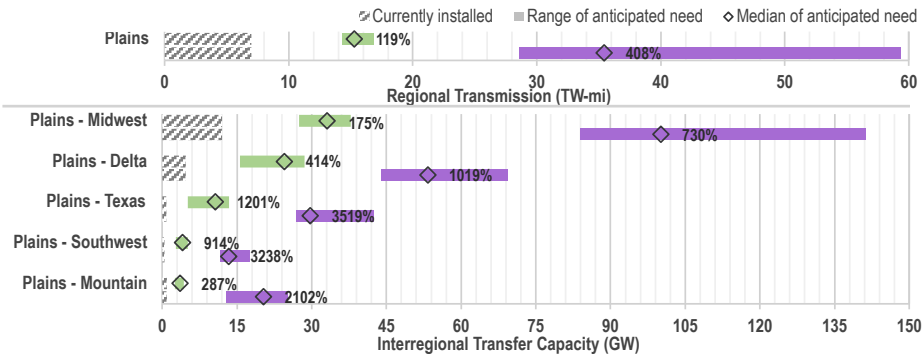
The average marginal value of transmission between the Plains region and Texas from 2012 through 2020 is equal to $42/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings are organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Plains region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **8.3 TW-miles of new within-region transmission by 2035** (119% growth relative to 2020) and **21.1 GW of new interregional transfer capacity with the Midwest region by 2035** (175% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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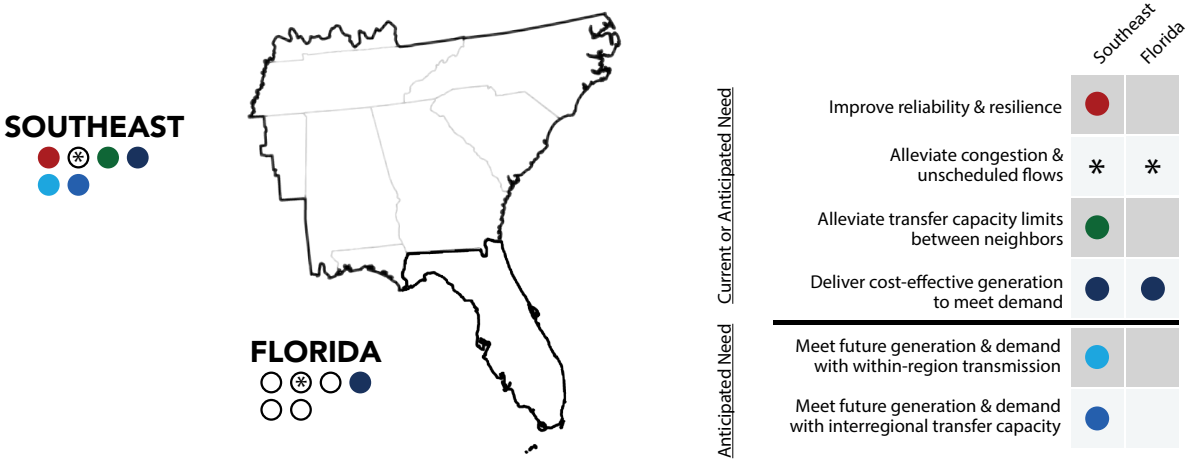
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# SOUTHEAST AND FLORIDA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Southeast and Florida. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




**Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

## FINDINGS OF TRANSMISSION NEED IN THE SOUTHEAST AND FLORIDA

*Fewer transmission system data and references were available for the Southeast and Florida than for many other regions of the country. These findings are incomplete for these regions given this lack of historic information.*

› **Improve reliability and resilience.** Extreme events in the Southeast can lead to generation shortages and blackouts, even when neighboring regions have excess generation. Increased transfer capacity between the Southeast and its neighbors would have helped Southeastern utilities service customer load during Winter Storm Elliott in 2022. Additional transmission infrastructure within the Southeast would provide reliable electric service to some areas as generation retirements occur. Hurricanes pose a threat to both the Southeast and Florida, and the hardening of the existing system would increase resilience to these intensifying events.

› **Alleviate transfer capacity limits between the Southeast and its neighbors.** Increased transfer capacity between the Southeast and its neighbors would result in consumer savings. Transfer capacity limits between the Southeast and its neighbors during Winter Storm Elliot led to forgone savings estimated to total nearly $100 million.

› **Deliver cost-effective generation to meet demand.** Both market forces and public policy are driving rapid changes in generation and demand in the Southeast and Florida. Capacity expansion modeling suggests that transmission upgrades within the Southeast and between the Southeast and Florida will be necessary to deliver cost-effective generation to load under a variety of different transmission technology scenarios.

### HELPFUL LINKS

› **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

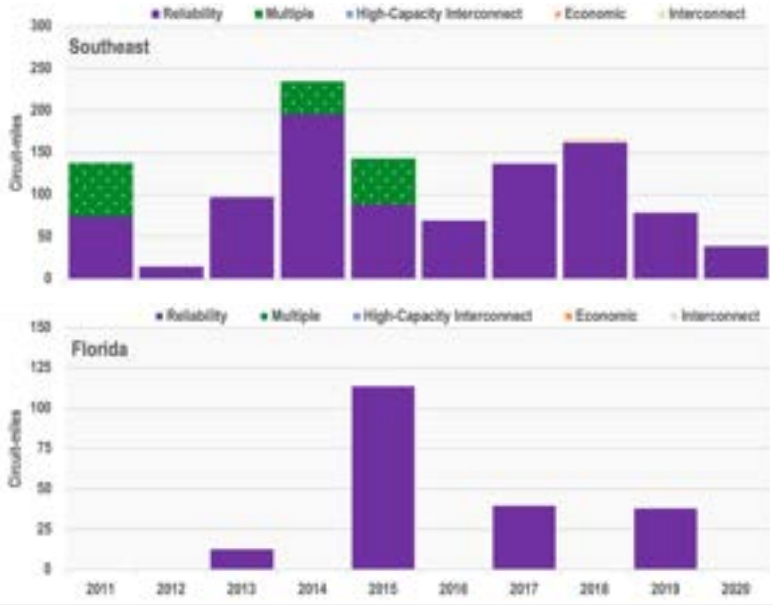
# FINDINGS OF TRANSMISSION NEED IN THE SOUTHEAST AND FLORIDA (CONT.)

› **Meet future generation and demand with additional within-region transmission.** The Southeast region will need an estimated 5.4 to 8 TW-miles of within-region transmission in 2035 (median 6.8 TW-miles, a 77% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Median growth of anticipated within-region transmission need in Florida was less than 25% relative to the 2020 system in 2035 under the same future scenarios.

› **Meet future generation and demand with additional interregional transfer capacity.** The Southeast region will need an estimated 5.8 to 9.9 GW of additional transfer capacity with the Mid-Atlantic region in 2035 (median of 6.9 GW, a 97% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller transfers between the Southeast region and the Delta (median value of 5.1 GW) and Midwest (median value of 4.5 GW) regions will also be required. Median growth of anticipated transfer capacity need between the Southeast and Florida was 32% relative to the 2020 system in 2035 under the same future scenarios.

# FINDINGS AT A GLANCE

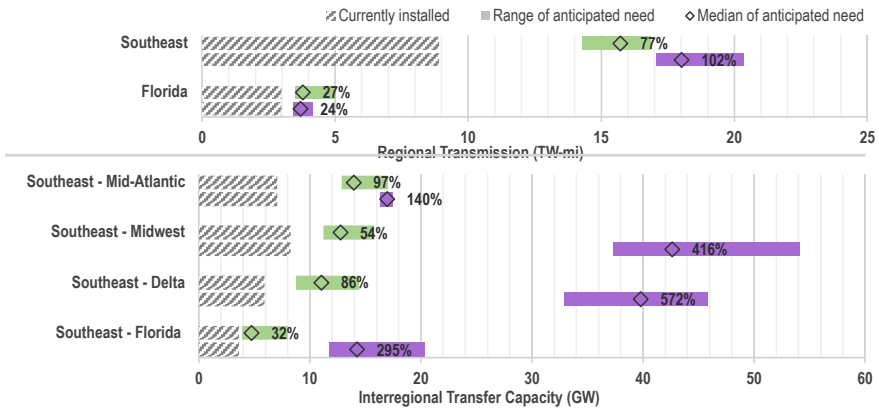
Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Projects energized from 2011 through 2020 in the Southeast and Florida were almost exclusively installed to **address reliability concerns**. Less than half of projects installed in the Southeast prior to 2016 were to **address multiple drivers**.

**Within-region transmission and interregional transfer capacity need for Southeast and Florida in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **6.8 TW-miles of new within-region transmission in the Southeast** (77% growth relative to 2020) and **0.8 TW-miles in Florida by 2035** (27% growth relative to 2020). **Significant new interregional transfer capacity growth is needed between the Southeast and its neighbors by 2035**.

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# SOUTHWEST REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Southwest region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.

**Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

## FINDINGS OF TRANSMISSION NEED IN THE SOUTHWEST REGION

› **Improve reliability and resilience.** The Southwest region is approaching system conditions that present the risk of load curtailment during extreme weather events and wildfires, especially as the region's reliance on variable energy resources to meet peak demand increases. Additional transmission upgrades in the near term would reduce risks to electricity reliability from extreme events.

› **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 31, located near the southern Colorado and northern New Mexico borders; additional transmission deployment would alleviate these unscheduled flows.

› **Alleviate transfer capacity limits between the Southwest region and Texas.** High congestion value of interregional transmission from 2012 through 2020 exists between the Southwest region and Texas, with an average marginal value of transmission equal to $25/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.

› **Meet future generation and demand with additional interregional transfer capacity.** The Southwest region will need an estimated 2.3 to 4.7 GW of additional transfer capacity with the Plains region in 2035 (median of 3.7 GW, a 914% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Southwest and Mountain (median value of 1.7 GW) and California (median value of 0.3 GW) regions may also be required.

### HELPFUL LINKS

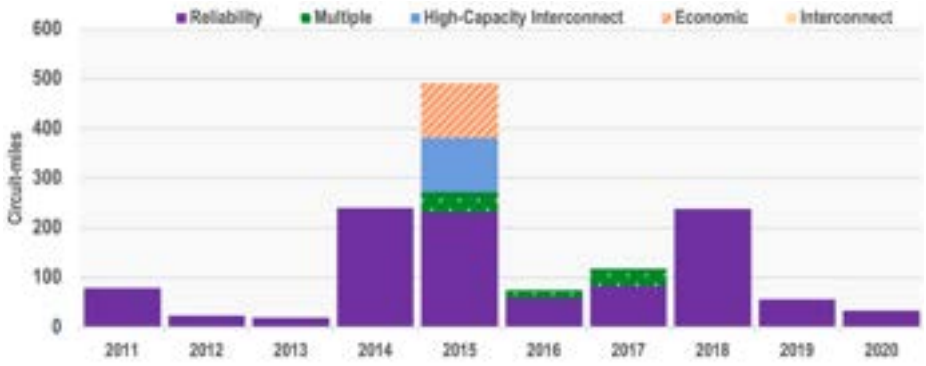
› **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Transmission projects energized over the last decade in the Southwest region were predominantly, but not exclusively, installed to **address reliability concerns**.

Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between the Southwest region and Texas**.

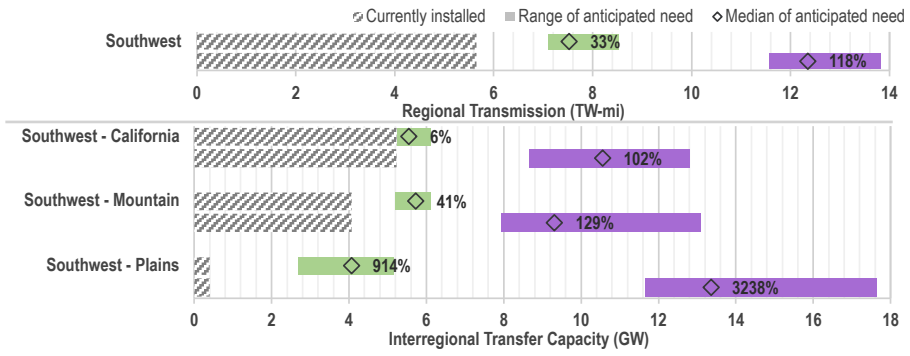
The average marginal value of transmission between the Southwest region and Texas from 2012 through 2020 is equal to $25/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for the Southwest region in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **1.9 TW-miles of new within-region transmission by 2035** (33% growth relative to 2020) and **3.7 GW of new interregional transmission deployment with the Plains region by 2035** (914% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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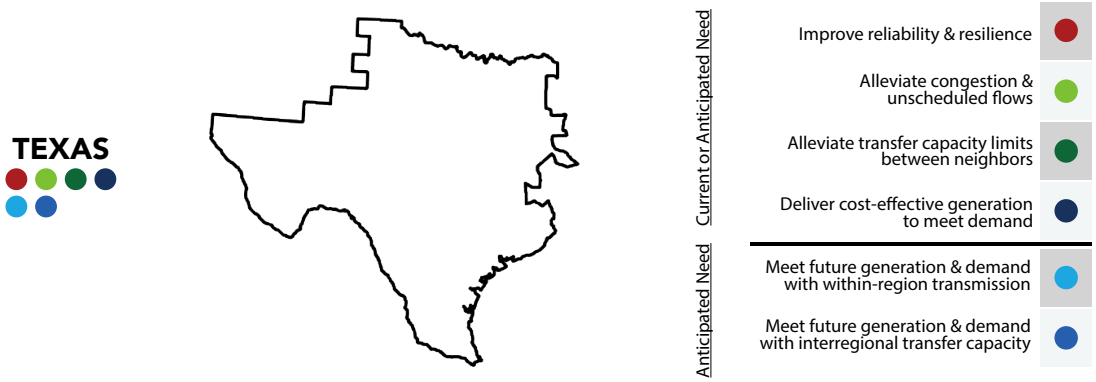
# 2023 NATIONAL TRANSMISSION NEEDS STUDY

# TEXAS

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. It identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Texas. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.




## FINDINGS OF TRANSMISSION NEED IN TEXAS

- **Improve reliability and resilience.** Limited transfer capacity with neighboring regions significantly affects the ability for Texas to address capacity shortages when the system is stressed under emergency conditions, such as those experienced during the February 2021 cold weather event. Increased bi-directional transfer capacities with neighboring regions would improve system reliability during extreme weather events.
- **Alleviate congestion and unscheduled flows.** High congestion values exist within Texas, indicating that additional transmission deployment would reduce system congestion and constraints. Texas is also anticipated to experience significant congestion due to increases in generation in the western part of the state and limited within-region transmission export capacity into demand centers such as the Dallas-Fort Worth and Houston areas.
- **Alleviate transfer capacity limits between Texas and the Plains region.** The highest congestion values of interregional transmission from 2012 through 2020 across the entire United States exists between Texas and the Plains region, ranging from $15/MWh to $69/MWh. Similarly high congestion values of transmission exist between Texas and the Southwest ($25/MWh) and Delta ($16/MWh) regions.
- **Deliver cost-effective generation to meet demand.** A high proportion of planned, cost-effective renewable resource additions within Texas are located in western Texas, which is a significant distance from load centers located in the eastern part of the state. Capacity expansion modeling suggests that transmission upgrades within Texas will be necessary to deliver cost-effective generation to load under a variety of different transmission technology scenarios.
- **Meet future generation and demand with additional within-region transmission.** Texas will need an anticipated 6.8 to 9.4 TW-miles of within-region transmission in 2035 (median 9.0 TW-miles, a 140% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** Texas will need an estimated 4.3 to 12.6 GW of additional transfer capacity in 2035 with the Plains region (median of 9.8 GW, a 1,201% increase relative to 2020 levels) to meet moderate load growth and high clean energy growth future scenarios.

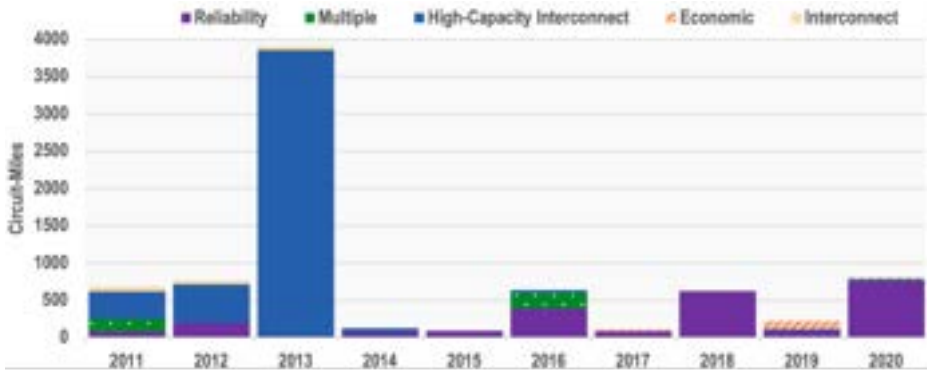
### HELPFUL LINKS

- **Read the full study at: www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

# FINDINGS AT A GLANCE



Circuit-miles of new or rebuilt transmission lines (≥ 100 kV) energized between 2011 and 2020 by project driver.




Texas predominantly installed **high-capacity (> 230 kV) transmission to interconnect generation** between 2011 and 2014. Projects energized from 2015 through 2020 were mainly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

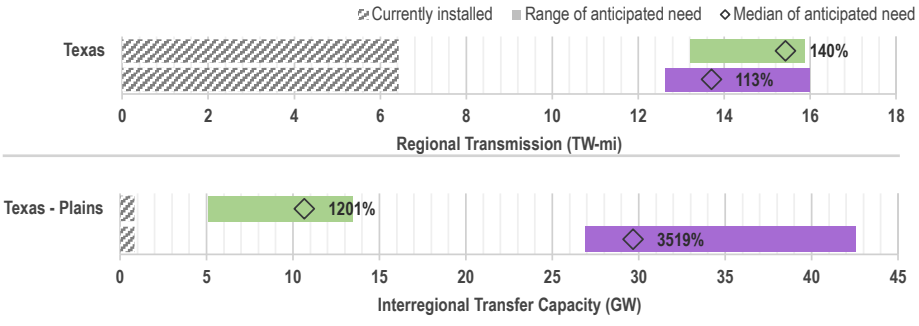
Wholesale market price differentials demonstrate that a **high value of new interregional transmission** exists **between Texas and the Plains region**.

The average marginal value of transmission between Texas and the Plains region from 2012 through 2020 is equal to $42/MWh.

Note: Wholesale market price data is limited for non-Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

**Within-region transmission and interregional transfer capacity need for Texas in 2035**

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.




Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **9.0 TW-miles of new within-region transmission by 2035** (140% growth relative to 2020) and **9.8 GW of new interregional transfer capacity with the Plains region by 2035** (1,201% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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# Appendix B: Comment Synthesis and Resolution

# National Transmission Needs Study

Public Comment Synthesis

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## List of Abbreviations

| | |
|---|---|
| ACC | American Chemistry Council |
| ACEG | Americans for a Clean Energy Grid |
| ACORE | American Council on Renewable Energy |
| ACP | American Clean Power Association |
| AE | Alliant Energy |
| AEA | Alaska Energy Authority |
| AEG | Advanced Energy Group |
| AES | The AES Corporation |
| AEP | American Electric Power Service Corporation |
| AEU | Advanced Energy United |
| AMP | Association for Modern Powerlines |
| AMPUA | Arizona Municipal Power Users' Association |
| AREGCBA | Accelerated Renewable Energy Growth and Community Benefit Act |
| CDR | carbon dioxide removal |
| CEBA | Clean Energy Buyers Association |
| CETA | Clean Energy Transformation Act |
| CHPE | Champlain Hudson Power Express |
| CLCPA | Climate Leadership and Community Protection Act |
| CPNY | Clean Path New York |
| CREZ | Competitive Renewable Energy Zone |
| DCC | Data Center Coalition |
| DER | distributed energy resource |
| DLR | dynamic line ratings |
| DOE | U.S. Department of Energy |
| EDF | Environmental Defense Fund |
| EEI | Edison Electric Institute |
| EIPC | Eastern Interconnection Planning Collaborative |
| EMS | Energy Management System |
| EPA | U.S. Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |

| | |
|---|---|
| FAS | Federation of American Scientists |
| FERC | Federal Energy Regulation Commission |
| FGRS | Future Grid Reliability Scenarios |
| FHWA | Federal Highway Administration |
| FPA | Federal Power Act |
| GDO | Grid Deployment Office |
| GEB | Grid-Interactive Efficient Buildings |
| GET | grid-enhancing technology |
| GW | gigawatt |
| HVDC | high-voltage direct current |
| ICCP | Inter-control Center Communications Protocol |
| IEDA | Irrigation & Electrical Districts Association of Arizona |
| IIJA | Infrastructure Investment and Jobs Act |
| IRA | Inflation Reduction Act |
| IRPA | Interregional Reliability Planning Assessment |
| ISO-NE | ISO New England |
| ITC | International Transmission Company |
| IRP | integrated resource plan |
| JHI | Juneau Hydropower, Inc. |
| JTIQ | Joint Targeted Interconnection Queue |
| LRTP | Long-Range Transmission Planning |
| MISO | Midcontinent Independent System Operator |
| MW | megawatt |
| NAERM | North American Energy Resilience Model |
| NCUC | North Carolina Utilities Commission |
| NEMA | National Electrical Manufacturers Association |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Corporation |
| NHA | National Hydropower Association |
| NIETC | National Interest Electric Transmission Corridors |
| NJBPU | New Jersey Board of Public Utilities |

| | |
|---|---|
| NREL | National Renewable Energy Laboratory |
| NYISO | New York Independent System Operator |
| NWA | non-wire alternatives |
| NYTOs | New York transmission owners |
| OSW | offshore wind |
| PIOs | Public interest organizations |
| PJM | PJM Interconnection LLC |
| PPTN | Public Policy Transmission Need |
| PSEG | PSEG companies |
| PUCT | Public Utility Commission of Texas |
| RFP | Request for Proposal |
| ROFR | right of first refusal |
| RTEP | Regional Transmission Expansion Plan |
| RTO | regional transmission organization |
| SCADA | Supervisory Control and Data Acquisition |
| SERTP | Southeastern Regional Transmission Planning |
| SPIGs | Southeast Public Interest Groups |
| SPP | Southwest Power Pool |
| SREA | Southern Renewable Energy Association |
| TVA | Tennessee Valley Authority |
| TWh | terrawatt-hours |
| USFS | U.S. Forest Service |
| VOLL | value of lost load |
| WATT | Working for Advanced Transmission Technologies Coalition |
| WECC | Western Electricity Coordinating Council |
| WIUFMP | Western Interconnection Unscheduled Flow Mitigation Plan |
| WSM | wide system model |

## Introduction

On March 6, 2023, the U.S. Department of Energy (Department or DOE) Grid Deployment Office (GDO) published a Notice of Availability of the National Transmission Needs Study and Request for Comment.[1] As mentioned in the Notice, Section 216(a) of the Federal Power Act (FPA), as recently amended by Section 40105 of the Infrastructure Investment and Jobs Act (IIJA), requires DOE to conduct a study of electric transmission capacity constraints and congestion every 3 years. The National Transmission Needs Study (Needs Study or Study) implements that statutory provision and replaces what was formerly known as the National Electric Transmission Congestion Study. Pursuant to section 216(a)(2) of the FPA, the Study would inform any decision to exercise DOE's National Interest Electric Transmission Corridor (NIETC) designation authority. The Needs Study will also inform DOE as it coordinates the use of other authorities and funding related to electric transmission. These include new authorities under the IIJA and existing DOE programs, such as grid-related research and development and financing authorities that support grid infrastructure development.

Comments were accepted by GDO via NeedsStudy.Comments@hq.doe.gov until midnight, April 20, 2023.

GDO asked ICF to provide a synthesis of the comment submissions received in response to the Notice. GDO received a total of 58 submissions. ICF has analyzed all submissions and prepared a narrative summary of the relevant ideas, issues, and concerns expressed by the submissions.

ICF's process for analyzing public comments relies on its commercial CommentWorks® software product, a web-based software solution for analyzing, sorting, tracking, summarizing, and responding to public comments. As a first step, ICF was granted access to the comment mailbox and downloaded all comment submissions to be imported into CommentWorks for analysis. Based on its review of the comments, ICF developed a hierarchical coding structure to include key issues identified in the comments. GDO reviewed this structure and approved its use in organizing the synthesis report. ICF staff then reviewed all unique comments, identifying within each submission substantive excerpts that should be bracketed and coded using the hierarchical structure to associate each bracketed excerpt with the issue(s) to which it applies. ICF staff then synthesized the content from the verbatim excerpt quotes from all submissions into the comment summaries that are included in this document. The comment summaries that follow are organized into issue topic areas, as indicated in the Table of Contents.

DOE reviewed all comments in full in addition to this comment synthesis and considered all comments in full when making decisions about how to revise the Needs Study based on the feedback received. Within each comment topic area, the Department provides a "Department Response," summarizing changes made between the draft Needs Study for public comment (draft Study) and the final version of the Needs Study published in October 2023 (final Study) in response to comments.

[1] U.S. Department of Energy. 2023. Notice of Availability of National Transmission Needs Study and Request for Comment, 88 Fed. Reg. 13811. Available at https://www.federalregister.gov/documents/2023/03/06/2023-04521/notice-of-availability-of-national-transmission-needs-study-and-request-for-comment.

# 1. General Comments

## 1.1. General Support

Several commenters express broad support for DOE's Needs Study. The Arizona Municipal Power Users' Association (AMPUA), Irrigation & Electrical Districts Association of Arizona (IEDA), Advanced Energy United (AEU), and the National Electrical Manufacturers Association (NEMA) note that the Study comes at a critical time as the country works to manage existing planning inadequacies and plan for efficient and cost-effective decarbonization. This section details comments that express support for the Study's methods, content, conclusions, and potential applications.

A few commenters appreciate DOE's approach to identifying national transmission needs. Public interest organizations (PIOs)[2] recognize that literature review, rather than original research, is a standard, scientifically sound methodology. NEMA appreciates DOE's recognition of regional differences, citing that future needs will be informed by market, policy, cultural, and topographical factors. It indicates that different solutions will be required to meet these differing needs, as is reflected in the Needs Study. The Environmental Defense Fund (EDF) supports DOE's iterative approach of alternating between the Transmission Needs and Transmission Planning studies, noting that they can inform and complement one another, as information and data changes.

The AES Corporation (AES) expresses support for DOE's needs-based, technology-neutral approach. AES supports the Needs Study's discussion of transmission needs to (1) increase reliability and resilience, (2) alleviate congestion, (3) reduce unscheduled power flows that are due to system constraints, (4) increase transmission capacity and transfer capability, (5) integrate renewable energy, and (6) support cost-effective generation. AES additionally supports DOE's intention to periodically update the Study.

The American Council on Renewable Energy (ACORE), Edison Electric Institute (EEI), American Clean Power Association (ACP), Southern Renewable Energy Association (SREA), and International Transmission Company (ITC) support the Study's research. ACP writes that the Study's conclusions reflect proper consideration of research and analysis conducted over the past decade. SREA remarks that the Study's research represents a wide range of subject matter expertise, geographic diversity, and concerns related to the power sector. ITC appreciates DOE's thorough consultation with relevant stakeholders throughout the research process. Similarly, EDF concludes that DOE undoubtably met its obligations to consult with affected entities, as defined in the FPA. It cites the 2006 transmission congestion study, in which DOE

[2] Natural Resources Defense Council, Sustainable FERC Project, RMI, Earthjustice, Sierra Club, National Wildlife Federation, Southern Environmental Law Center, Western Resource Advocates, Montana Environmental Information Center, National Audubon Society, and Alliance for Affordable Energy collectively responded to GDO's Request for Comment.

failed to engage with relevant stakeholders,[3] and asserts that, in comparison, the Needs Study engaged in earlier, more comprehensive, and more inclusive engagement.

Some commenters express support for the Needs Study's scope and detail. AEU writes that while there are several studies that analyze specific regions or elements of the grid, the Needs Study presents an appropriate national and regional depiction of transmission needs that cannot be found elsewhere. In opposition to a critique by Southeastern Regional Transmission Planning (SERTP) Sponsors stating that the Study's broad scope extends beyond statutory authority, ACORE strongly disagrees and argues that the draft Study's scope is needed to demonstrate existing infrastructure inadequacies. Similarly, the New Jersey Board of Public Utilities (NJBPU) states that the very purpose of the Study is to identify gaps in existing planning efforts and argues that DOE properly balanced bottom-up and top-down planning efforts. It fully endorses the Study's choice to examine regional and interregional needs, noting that it complements traditional planning processes that prioritize local concerns. SREA and PIOs share this sentiment. SREA specifically notes the Needs Study addresses the limited scope of utility integrated resource plans (IRPs), which often do not consider needs beyond their service territories. In response to a comment by SERTP Sponsors, stating that analyzing forecasted transmission constraints is beyond the scope defined in the FPA, SREA argues that DOE's research predicts future congestion and capacity constraints and excluding these insights from future grid conditions would be negligent.

AMPUA, IEDA, ACP, American Electric Power Service Corporation (AEP), Consolidated Edison Company of New York (Con Edison), Gallatin Power, New York transmission owners (NYTOs), PSEG companies (PSEG), Association for Modern Powerlines (AMP), and PJM Interconnection LLC (PJM) generally agree with the Needs Study's overall findings, such as the need for transmission expansion to manage a changing resource mix, decarbonization efforts, extreme weather events, and existing infrastructure inadequacies. ACP and Americans for a Clean Energy Grid (ACEG) also agree that transmission expansion will encourage a diversified and low-cost future energy mix. They express support for the Study's conclusions across all growth scenarios. In response to a comment by SERTP Sponsors claiming that the existing southeastern transmission system cannot support an additional 2 gigawatts (GW) of generation capacity, SREA argues that this is justification for the Needs Study and evidence that current planning efforts are not sufficient. PJM agrees that there are potential benefits to transmission expansion, under the assumption that it is appropriately planned and sited. EEI notes that the Needs Study's conclusions on the primary needs and challenges facing each region of the country's grid are consistent with findings by local and regional planners and stakeholders in those areas. Similarly, ACEG says that the Study reinforces the findings of multiple experts.

Blue Lake Rancheria Tribe asserts that transmission needs in Tribal lands are critical. It explains that Tribal nations have been widely excluded from national efforts to support electrification in rural and remote areas of the country. Consequentially, the transmission infrastructure serving

[3] California Wilderness Coalition v. United States DOE, 631 F.3d 1072 (9th Cir. 2011).

Tribal lands is at capacity and not prepared to withstand impending climate disasters or to support necessary electrification and clean energy efforts.

Two commenters discuss the need for reliable power and increased transmission infrastructure within their respective industries. The Data Center Coalition (DCC) emphasizes the role of reliable transmission infrastructure in the data center economy. It explains that inadequate transmission infrastructure is already impeding operations, as congestion prevents the utilization of available generation facilities. DCC notes that this is costly, both for individual businesses and workers, and for the national economy. Similarly, the American Chemistry Council (ACC) emphasizes the chemical industry's large demand for electricity, and subsequent transmission needs, warning that demand will likely increase with electrification efforts.

Avangrid, Con Edison, AEU, ACP, AEP, Grid United, National Grid, NYTOs, and AMP specifically support the need for, and benefit of, increased interregional transfer capability. These commenters cite at least one of several factors, including the critical role of interregional transmission infrastructure in the clean energy transition, ensuring reliability, meeting state and federal climate targets, managing growing customer demand, and providing economic benefits. AEU writes that DOE provides indisputable evidence of the need for interregional transmission expansion. Avangrid supports the need for increased international transfer capability and a group of PIOs also supports the need for transmission between interconnections and utility service area.

Some commenters confirm the need for transmission expansion in specific regions, including within PJM, in New York and in New England, between New York and New England, and between Canada and New England. Southeast Public Interest Groups (SPIGs) write that the Needs Study accurately portrays future transmission needs in the Southeast and adds that these infrastructure inadequacies are already compromising the region's grid.

ACP and SPIGs agree that transmission deployment is not keeping up with changing needs of the grid. Specifically, the commenters note that despite the importance of interregional transmission, it has received negligible investment in recent years.

Several commenters anticipate that the Needs Study will be useful. SREA states that it provides value to non-regional transmission organization (non-RTO) regions, especially the Southeast. AEU remarks that the Study helps improve transmission infrastructure investments. Con Edison mentions that the Study is helpful to understanding future needs and prompts discussion on the vital role of transmission in clean energy and decarbonization efforts.

ACEG, EEI, Con Edison, DCC, SREA, NYTOs, and PIOs anticipate that the Study will be a beneficial tool for those participating in transmission planning and policymaking. ACEG refers to the Study as a foundational document that each transmission planner, regulator, energy policymaker, and stakeholder should read to better understand the need for and benefits of transmission expansion. AEU states that the Study helps stimulate coordinated regional and interregional planning efforts. SREA indicates that the Study offers context for planners and stakeholders, as they consider current and future grid conditions. NYTOs echo this sentiment, adding that regulators could benefit from its contents. AEU asserts that the Needs Study is an essential benchmark and guidepost in the ongoing effort to mitigate regulatory and planning barriers to

transmission development. AEU explains that by creating a set of standard facts relating to regional transfer capability and need, the Needs Study can serve as tool for regional planning entities, as they collaborate and seek mutually beneficial solutions to grid challenges.

Other commenters anticipate that the Study could serve as an important resource for federal programs related to transmission deployment, for both DOE and program applicants. These commenters note that the Study could be valuable in the potential designation of NIETCs and programs funded through the IIJA and Inflation Reduction Act (IRA). ACORE writes that the Needs Study encourages the Federal Energy Regulatory Commission (FERC) to act on the pending proposed rulemakings on regional transmission planning and cost allocation[4] and generator interconnection procedures and agreements.[5]

Lastly, a few commenters support specific aspects of the Study's content. These statements of support are itemized below:

- ACORE and AES support the Study's definition of transmission need.
- AES supports the Study's stated purpose.
- AEP appreciates the Study's acknowledgment that needs will shift over time.
- EEI and Alliant Energy (AE) appreciate the Study's detail on previous and existing capacity constraints and congestion as it provides useful context.
- The Electric Reliability Council of Texas (ERCOT) appreciates the Study recognizes that Texas built more transmission than other regions.
- Utah Public Lands Coordinating Office supports the Study's inclusion of Western Interconnect Unscheduled Flow Mitigation Plan in its discussion of unscheduled flows on Qualified Paths connecting Colorado to its neighbors.

### Department Response

The Department thanks the commenters for their comments of general support. The Department did not make any changes in response to these comments.

## 1.2. General Opposition

This section details comments expressing broad opposition to the Needs Study, as well as objections to the Study's methods and conclusions.

A few individuals express opposition to the basis of the Study and what they view as political or parochial goals of the Study. One individual, Keryn Newman, criticizes the discrepancy between needs identified in the 2020 Congestion Study and the draft Study, stating that in 2020, DOE did

[4] Federal Energy Regulatory Commission. 2022. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000, 179 FERC 61,028. Available at https://www.ferc.gov/media/rm21-17-000.

[5] Federal Energy Regulatory Commission. 2022. Improvements to Generator Interconnection Procedures and Agreements, Docket No. RM22-14-000, 179 FERC 61,194. Available at https://www.ferc.gov/media/rm22-14-000.

not find a need to designate transmission corridors.[6] In contrast, this report finds significant transmission need "in an area so vast that if the DOE were to designate corridors to solve it, the entire continental U.S. would be one gigantic 'corridor.'" Newman concludes that this discrepancy can only be attributed to the fact that the studies "are not based on data and science, but on political goals." Another individual, Janice Cooper, raises similar concerns. Econwerks, states that the Study should be held to much higher scientific standards to meet President Biden's commitment to follow the science. By analyzing existing studies rather than conducting independent research, Econwerks argues that the Needs Study presumes the outcome. Econwerks states that conclusions are not objective, neutral, nor independent and are not anchored in sound science, but instead reflect a "panoply of economic interests with parochial goals."

A couple of commenters express skepticism of the report's utility. PJM questions the Needs Study's role in designating transmission corridors. It argues that the Study's sweeping conclusions are so broad that they could serve as a basis for designating the entire country, or no areas at all, as a transmission corridor. PJM argues that the Needs Study does not offer "the degree of specificity and record" needed to support corridor designation. SERTP Sponsors offer general critique, stating that if the Study "serves more than informational purposes, it must meet a higher bar."

SERTP Sponsors object to the basis of DOE's conclusions, arguing that the research is untethered from state data and planning efforts. Furthermore, SERTP Sponsors state that the Needs Study only considers the benefits of transmission expansion, without a necessary, complementary analysis of transmission costs. Without this analysis, SERTP Sponsors argue that DOE is ill equipped to make transmission corridor designations, which will encourage wide-scale transmission expansion and require significant financial investment. SERTP Sponsors suggest that DOE consult with planning coordinators and transmission planners registered with the North American Electric Reliability Corporation (NERC) to better understand local realities and planning efforts, which include data on transmission costs.

A couple of commenters object to the Study's conclusions. Janice Cooper disagrees with the need for transmission expansion. Keryn Newman argues that transmission cannot solve the needs identified in the Study. Newman explains that regions of the country are already experiencing resource adequacy concerns and increased transmission will only exacerbate the issue, as regions are required to serve both local load and the load of their neighbors. Newman asserts that transmission does not produce electricity, implying that DOE should consider the need for increased generation, rather than transmission capacity.

SERTP Sponsors object to the Study's conclusion that transmission expansion will be necessary and beneficial in the Southeast. They argue that the cost to increase transmission capacity and interregional transfer capability would outweigh the benefits. SERTP Sponsors conclude that low customer costs, low congestion, high reliability, and successful implementation of the

[6] U.S. Department of Energy. 2020. National Electric Transmission Congestion Study, page vi. Available at https://www.energy.gov/oe/articles/2020-national-electric-transmission-congestion-study.

energy policies all indicate that the southeastern grid is working efficiently and does not require build-out. SERTP Sponsors disagree with the Study's claims that utility planning has a limited scope and that the Needs Study is a more thorough assessment of transmission need. They believe their transmission planning, informed by IRP and Request for Proposal (RFP) processes, is more comprehensive.

#### Department Response

The Department thanks the commenters for their comments of general opposition. The Department believes that analyzing and reviewing previously published scientific and industry data and reports is a valid and valuable methodology to determine the existence of need. Synthesizing existing publications can identify commonalities, contradictions, and gaps in research to help form an evidence-based, comprehensive understanding of transmission need. Leveraging existing research also helps enable DOE to provide timely, relevant insight pursuant to its statutory mandate to conduct a study every 3 years. DOE believes this approach can complement new transmission system modeling and specific project planning, as performed by industry. The Department also believes that this study complements its own modeling and analysis work in the National Transmission Planning (NTP) Study and related work.

The Department notes that findings of transmission need are organized by broad geographic regions—the boundaries of which align with the power grid jurisdictional boundaries—to help focus readers' attention on areas of interest, but these regions do not align with an area that could be designated as a NIETC (pronounced as \NIT-see\). As stated on page 1, the Needs Study does not designate NIETCs. The Department has added content to clarify how the Needs Study interrelates with the NIETC designation processes (pages 1–2).

Changes were made to *Section V.a. Reliability and Resilience* to better explain that transmission is one available solution to address resource adequacy concerns, in addition to generation and demand-side solutions (pages 59–62).

The Department has removed the *Section I. Introduction* passage referenced by SERTP Sponsors regarding utility planning processes from the final Study. The Department maintains that the Needs Study is meant to complement, and not displace, the vital transmission planning performed by utilities. Further, the Department maintains that because the Needs Study is a review of previously performed studies and does not include any new system modeling, reliability, and cost analyses of specific projects—comprehensive components of planning performed by transmission planners—are not within scope of this effort. The Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the final Study to further explain how Study findings can complement existing power sector planning efforts.

### 1.3. Executive Summary and Introduction

This section includes any comments related to the Needs Study's Executive Summary.

AMPUA and IEDA emphasize that electrification could cause power demands to double from 2020 to 2050 and recommend that the Executive Summary adequately stress the need for transmission capacity to manage this demand growth and the lead time for such capacity additions.

CEBA recommends adding a table with regional and interregional transfer capabilities and a summary on the national key takeaways from the Study to the Executive Summary. Additionally, CEBA recommends differentiating existing and anticipated transmission needs to inform prioritization.

#### Department Response

In response to comments on the draft Study, the Department has restructured the Executive Summary in the final Study to provide more context surrounding national and regional takeaways from each section, including key summary graphics from final Study Sections III–VI. The revised Executive Summary more clearly distinguishes between current and anticipated future needs. New additions include a brief discussion of capacity expansion modeling future scenarios and how increasing power demands are factored into the scenarios.

The Department also inserts a more robust discussion of the need for additional transmission due to load growth (pages 87 and 89) in *Section V.c. Generation and Demand Changes*, which encompasses the impacts of increased electrification of end-use technologies.

### 1.4. Purpose and Application of the Study

Several commenters urge DOE to provide more context indicating the purpose and application of the Needs Study.

ACP requests clarification on how DOE will use the Study for the Transmission Facilitation Program, public-private partnerships through the Power Marketing Administrations, and other transmission-related loan and grant programs. ACP, AEU, Clean Energy Buyers Association, DCC, EEI, ACEG, and PJM urge DOE to clarify how it will apply the Needs Study to designate transmission corridors. PJM explains that the Needs Study lacks the details necessary to understand transmission needs in the context of corridor designation. For example, it notes that the Needs Study identifies areas in PJM with congestion but does not explain how transmission investments within specific zones could alleviate this. PJM states that the Study's general observations and silence on how these observations relate to corridor designation, "leave the Secretary with little in the way of guidance and support and the public with little information" on how corridor decisions will ultimately be made.

ACEG asks that DOE address if, and how, it plans to facilitate and improve interregional planning efforts. Similarly, ACP urges DOE to explain how it will employ its statutory authority to address the transmission needs identified in the Study. PIOs request DOE recommend additional studies that should follow the Needs Study.

A few commenters request that DOE explain how planners, regulators, and other stakeholders should use the Study. DCC notes that it is unclear how the Study can be used in planning and regulatory processes. It recommends adding a section to the report detailing best practices for using the Study. Similarly, CEBA requests detailed and concrete examples of how states, and regional and local planning entities, can use the Study. ACEG requests guidance on how state and Tribal planners can parse out which of the Study's insights, which are considered at a regional bases, are relevant to their respective planning processes.

ACP and EEI recommend that DOE detail, through guidance or regulations, how applicants to federal transmission programs can use the Needs Study to better their applications. ACP recommends that DOE use the Needs Study to evaluate applications to federal transmission programs, prioritizing applicants whose projects address needs identified in the Study.

#### Department Response

In response to comments requesting additional context surrounding the purpose and application of the Needs Study, the Department has included additional context in Section I to discuss the purpose of the Study and how the Department plans to utilize its findings. Notably, the Department has added content to clarify how the Needs Study interrelates with NIETC designation processes (pages 1–2).

In response to comments requesting more information about how planners, regulators, states, and other stakeholders should use this Study, the Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the Introduction, which discusses how entities may utilize final Study findings and how they can be incorporated into existing transmission planning processes.

The Department does not make additional revisions to the final Study in response to commenter requests for clarity on how DOE will use the Study to guide transmission-related funding. As noted in *Section I. Introduction* (page 1) of the final Study, the Department will use the findings of this Study as it coordinates the use of its authorities and funding that relate to electric transmission, including implementing the many grid resilience and technology investment provisions of the IIJA and the IRA.

### 1.5. Editorial Changes

Several commenters offer editorial suggestions. This section includes comments related to language, web links, and figures and tables.

ISO New England (ISO-NE) remarks that "the first sentence of the fourth paragraph in Section V.b. of the draft Study regarding the Future Grid Reliability Scenarios (FGRS) may be misleading" and recommends replacing it with:

"ISO-NE (2022) similarly found in their Future Grid Reliability Scenarios (FGRS) that even in a mild weather year, such as the 2019 weather year used in the FGRS, weather events can pose significant challenges to maintaining electrical grid reliability under a high variable energy future."

The Federation of American Scientists (FAS) mentions that the Needs Study's language describing the IRA and IIJA in relation to the Study's modeling scenarios is misleading. Specifically, FAS cites pages 84–85, which define the Moderate/Moderate, Moderate/High, and High/High scenario groups in relation to the passage of the IRA and IIJA and expresses concern that the current phrasing implies that moderate transmission expansion and high renewable penetration are inevitable, given the passing of the IRA and IIJA. They cite Figure VI-6 in the Needs Study to assert that, even with this historic federal legislation, current transmission plans will not be adequate to accommodate an 80% share of renewable energy and "such an outcome must be chosen by multiple actors across all levels of government, industry, and

society." FAS encourages DOE to make this clear and provides the following explanation as a possible substitute:

"The Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted. The Moderate/High group best represents a future power system, now within the range of possibility due to the IRA and IIJA, but still requiring significant action from public, private, and community actors. The High/High group represents a future power system where new clean energy and electrification of demand-side energy policies are enacted."

The Western Electricity Coordinating Council (WECC) offers the following corrections:

- "WECC footprint is not a market." In two instances on page 47, and a third on page 75, it recommends using the term "Western Interconnection" instead of "the WECC" and "WECC region."
- The "Northwest Power Pool (NWPP)" was renamed the "Western Power Pool (WPP)."
- On page 35, the Needs Study references the "2013 WECC Paths Report." WECC offers a link to the updated "2023 Path Rating Catalog."[7]
- On page 32, the "WIUFMP FERC tariff" link does not work. WECC offers "the related Unscheduled Flow Mitigation Plan (WIUFMP), published in 2019'" and explains that it could be "a useful, contemporary reference for inclusion or replacement."[8]

Several commenters provide suggestions on figures and tables. AMPUA and IEDA suggest adding a table to the Study summarizing existing transmission capacity between regions. Comments on existing tables and figures are detailed below.

- **Figure IV-2:** AE recommends describing regional and federal policies, such as FERC Order No. 1000, which could explain these data.
- **Figures IV-2 and IV-3**: AE suggests representing these data, on the proportion of circuit-miles installed by developer type and project driver, at a regional rather than national level. AE explains that doing so would allow for a reader to analyze how regulatory environment and market forces, which differ regionally, shape investment patterns. Additionally, it suggests including the share of data that is related to transmission projects meant to replace existing lines, explaining that these projects are typically excluded from planning processes.
- **Figure IV-3**: AE recommends detailing how MAPSearch defines each project driver. Additionally, it suggests showing the data in Figure IV-3 by developer types, as defined in Figure IV-2 and explaining whether or not these projects were incorporated into regional planning processes. AE also recommends adding additional context to explain the figure's trend, such as the policy and regulation factors that might have contributed

[7] Western Electricity Coordinating Council. 2023 Path Rating Catalog—Public Version. Available at https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf.

[8] Western Interconnection Unscheduled Flow Mitigation Plan. Available at https://spp.org/Documents/62460/081919%20WIUFMP%20Tariff.pdf.

to the large decrease in the proportion of installed circuit-miles driven by high-capacity projects in 2013.

- **Figure IV-10**: WECC remarks that this figure, illustrating WECC Balancing Authorities, is outdated and provides an updated version as an attachment.
- **Figure V-2**: AMPUA and IEDA, and AE remark that "80%" appears twice on the x-axis. AE recommends adding a line of best fit to summarize the relationship between the share of clean energy and transmission investments. Furthermore, it recommends removing outliers that would skew this line of best fit to ensure it is not misleading. Additionally, AE recommends adding context to explain why estimates in Figure V-2 differ widely and suggests including insights from DOE's report titled *Queued Up… But in Need of Transmission*. AMPUA and IEDA state that while DOE highlights the $500 billion cost of achieving 80% clean energy, the figure and context lack detailed information on regional transmission line construction costs.
- **Table VI-4:** AMPUA and IEDA note that the estimated capacity transfer increase from Southwest to Texas is missing.

### Department Response

The Department made several changes based on editorial suggestions received during the public comment period. Specifically, the Department:[9]

- Made corrections to ISO-NE FGRS study reference using suggested language from ISO-NE comments.
- Revised language describing the scenario group descriptions in Section VI.a. of the final Study in response to comments suggesting additional language to clarify the Moderate/High capacity expansion modeling scenario groups. Specifically for the Moderate/High group, the Department has added that while Moderate/High scenarios are now within the range of possibility given current policies, they are not inevitable and will require action (pages 118–119).
- Made changes in response to WECC's suggestion for including new reference to "2023 Path Rating Catalog" (updated Figure IV-14, page 45) updated the broken "WIUFMP FERC tariff" link (page 19), removed references to NWPP, and replaced references of "WECC" to the "Western Interconnection" as appropriate throughout the Study.
- Included additional Figures IV-4 and IV-5 (pages 26–27) in the final Study to display historic developer type data (national level data presented in Figure IV-2 in the draft Study) at the regional and voltage class levels.
- Included additional Figure IV-7 (page 30) in the final Study to display historic transmission driver data (national level data presented in Figure IV-3 in the draft Study) at the regional level.
- Added more information for draft Study Figure IV-3 (final Study Figure IV-6, page 28) on the driver definitions and circumstances behind driver trends in certain regions (pages 27–31).

[9] Figure labels listed in this section correspond to figure labels as they appear in the final Needs Study.

- Updated Figure IV-10 (now Figure IV-15, page 47) with a more up-to-date WECC balancing authority map.
- Corrected Figure V-2 (now Figure V-6, page 75) x-axis where "80%" appears twice.

The Department notes that the six capacity expansion modeling studies that form the basis of data analysis in Section VI did not model increased transfers between the Southwest and Texas, so there is no data for this potential transfer to add to Table VI-4.

## 1.6. Other Comments Related to the Content of the Study

EDF suggests that DOE clearly define the term transmission value and its metric for assessing such value. EDF states that the Needs Study references "transmission value" and the "value of transmission," without defining these terms. It argues that this limits the usefulness of certain Study insights, such as declarations of investments that would provide the greatest transmission value. EDF urges DOE to explain whether these terms reflect (1) net or gross benefit value and (2) strictly economic value or an assessment of total benefits, including factors such as reliability and environmental impacts. It also suggests that if the term currently has multiple meanings in the Study, DOE should be consistent and use different language to clarify this difference. EDF asserts that this clarification would make the Study's conclusions more meaningful.

CEBA requests clarification on the meaning of each capacity expansion model scenario group, such as the level and pace of decarbonization in the power system assumed in each group.

AE recommends additional context to inform the reader why the Study's identified transmission needs exist. For example, as noted in Section 1.5, AE notes that Figure IV-3 illustrates a large decrease in the proportion of installed circuit-miles driven by high-capacity projects in 2013 without sufficient explanation. While there are external forces affecting this trend, including policy and regulation, AE is concerned that readers might lack this context. Specifically, it fears transmission owners might use the Study to justify large transmission investments, without implementing the necessary reforms to plan for a cost-effective grid. CEBA recommends adding a section to the Needs Study to describe methodology. It requests an explanation on (1) why DOE chose to examine existing literature, (2) the limitations of the Study, (3) the relationship between the Needs Study and the NTP Study, and (4) how and why the Study might underestimate transmission needs.

National Grid remarks that considering the impacts of specific transmission projects is vital to contextualizing need. Specifically, it argues that projects require detailed modeling and coordination with entities on both sides of the interface to determine the benefits and limitations of a specific upgrade.

AE recommends that the Study include a discussion on how transmission build-out will affect customer costs. It cites an S&P Global Market Intelligence finding on the increase in base rates in Midcontinent Independent System Operator (MISO) as evidence that transmission rates

account for a considerable portion of customers' monthly utility bills.[10] AE further notes that the words "rate base" are not mentioned in the Needs Study and asserts that the customer impacts of transmission investments cannot be an afterthought when planning the grid. Keryn Newman criticizes the Study's conclusion that large-scale transmission build-out is cost-effective. Newman cites the Study's "vague claims of 'economies of scale,'" arguing they are never justified and allow DOE to avoid a comprehensive analysis of the cost of transmission.

The Center for Biological Diversity urges DOE to continue to exclude the North American Energy Resilience Model (NAERM) from this planning effort. It references the 2020 Grid Congestion Study,[11] which relied on NAERM. It explains that this model creates a pretext for continued reliance on fossil fuels and supports its omission from the draft Study. It asserts that NAERM should not distract DOE from publishing the Needs Study in a timely manner.[12]

SREA argues that given existing constraints and MISO's current planning efforts, the Needs Study should prioritize connecting MISO South (Delta) and MISO North (Midwest), rather than connecting these regions to the Southwest Power Pool (SPP). SREA cites recent weather events, including the cold weather bulk electric system event in January 2018, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022 to illustrate that existing infrastructure is not equipped to accommodate power flows between the Midwest and Delta regions that are necessary to ensure reliability. Specifically, SREA explains that during these events there was energy in MISO North that was stranded and unable to support load in the Delta region because of system constraints. It also notes that connecting the Midwest and Delta regions will only be valuable if MISO's Long-Range Transmission Planning (LRTP) Tranche 3 effort, which addresses transmission constraints within the Delta region, is successful. SREA explains that congestion in southern Louisiana and southeastern Texas is limiting power flow in the area and contributing to high costs of interconnection. It cites MISO's revised Future 2A forecast, which projects 80 GW of renewable energy, hybrid, and energy storage resources will be deployed in the Delta region by 2037, to further emphasize the need for transmission upgrades within the Delta region.[13]

PJM provides additional context regarding the February 2021 cold snap. During this event, PJM asserts that it supplied an unprecedented amount of electricity to neighboring systems. During

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[10] S&P Global Market Intelligence, Transmission rate base, authorized returns on equity of U.S. utility operating companies in MISO.

[11] U.S. Department of Energy. 2020. National Electric Transmission Congestion Study. Available at https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf.

[12] The Center for Biological Diversity raised some of these issues in an earlier letter to the agency. See Letter of July 20, 2022, https://www.biologicaldiversity.org/programs/public_lands/pdfs/DOE-Grid-Study-Letter-072022.doc.pdf.

[13] Midcontinent Independent System Operator. 2023. Future 2A Expansion & Preliminary Siting Presentation, slide 8. Available at https://cdn.misoenergy.org/20230310%20LRTP%20Workshop%20Item%2002%20MISO%20Future%202A%20Expansion%20and%20Preliminary%20Siting628178.pdf.

peak hours of the event, PJM's exports totaled to three times higher than the 2020/2021 winter average during peak. Accordingly, PJM concludes that "overall, the grid performed reliably." It also clarifies that transfer limitations during this event can mostly be attributed to constraints in neighboring systems, which could not support a greater volume of imports, rather than facilities in PJM or along the seam. PJM hopes DOE will consider these notes in the Needs Study's discussion of the cold snap.

DataCapable states that there is a need to increase interoperability and shareability of distribution and transmission data, to address a disconnect between utilities, vendors, and distributed energy resources (DERs) manufacturers. It encourages DOE to review Outage Data Initiative Nationwide. Additionally, it emphasizes the need to standardize data sharing between microgrid operations, utilities, and transmission operators to accommodate greater diversity of generating resources on the grid.

SERTP Sponsors remark that the draft Study did not meaningfully address their comments on the consultation draft. Instead of incorporating their suggestions, SERTP Sponsors argue that the draft Study summarizes SERTP Sponsors' concerns in Appendices A-1 and A-2 and cross-references to moderately relevant responses. SERTP Sponsors repeat their recommendations to (1) incorporate state resource projections, (2) include cost analysis, and (3) coordinate EIPC.

SPIGs provide detailed critiques of SERTP Sponsors' comments in Appendix A-2. SPIGs argue that SERTP Sponsors have a vested financial interest in ignoring the needs identified in the Study. SPIGs provide detailed counterarguments to address SERTP Sponsors' comments 43, 55, 83, 97, 118, 128, 129, 132, 147, 148, 149, and 150, as enumerated in Appendix A-2.

### Department Response

In general, the term *value* is used colloquially to refer to both quantifiable cost savings and, for example, non-monetized societal benefits. The underlying studies which use this terminology reviewed in the Needs Study may also have their own definition and use. When the term *value* has a specific meaning in the context of an underlying study, it is defined. For example, the research underlying *Section IV.b. Market Price Differentials* defines *value* as "the energy arbitrage potential, that is, the difference in price between two locations," (page 36).

In response to comments requesting more insight into details of the capacity expansion modeling scenario groups, the Department has provided more context and information regarding scenario specifics in *Section VI.a. Included Studies and Scenarios* of the final Study (pages 118–119). The Department has also added a list of scenario names and associated details, including excluded scenarios, to the Supplemental Material (Table S-6, pages 40–43).

As noted in the Department's response to editorial suggestions above and in response to comments requesting additional information about the drivers for historical transmission installation trends, the Department has provided additional context behind historical transmission installation trends between 2011 and 2020 in *Section IV.a. Historical Transmission Investments* of the final Study (pages 28–31).

The Department included a description of its methodology for choosing publications in the opening paragraphs of *Section V. Current and Future Need Assessment and Identification of*

*Transmission Benefits through Review of Existing Studies*: "The literature includes reports from the U.S. Government, national laboratories, academia, consultants, and a cross section of industry participants that incorporate quantitative and qualitative measures of electricity transmission needs. Reports were chosen on the basis of geographic diversity, diversity among sources, and author subject matter expertise, and to cover a range of critical reliability and congestion issues faced by the transmission system today," (page 52).

In response to comments about the chosen methodologies underestimating transmission need, the Department added several clarifications that full system need may not be captured in the final Study, especially where a lack of reviewable data exists. An example clarification is provided in the Executive Summary: "…there are gaps outside of RTO/ISO regions where information regarding the economic value of congestion is not available; these gaps do not reflect the absence of transmission needs but rather the absence of market data with which to calculate price differentials," (page v).

The Department agrees that additional modeling of the benefits of specific transmission lines is important to understand how they can meet system needs. The Department added *Section I.a. How to Use This Needs Study* (pages 2–4) to address this and other comments. Relatedly, cost analysis of any specific project is vital to understanding how benefits may justify the investment costs. As this Needs Study does not analyze the specifics of any individual transmission project, cost analysis is considered out of scope. Example investment costs for system-wide transmission studies were considered in Figure V-6 (page 75).

No new transmission modeling was conducted as part of this final Needs Study. As such, the NAERM model was not utilized in this iteration of the Study.

In response to comments requesting more information regarding transmission limitations between MISO South (Delta) and MISO North (Midwest), the Department has included additional references and context in *Sections V.a. Reliability and Resilience* (page 52–63) and *V.b. Regional Congestion and Constraints* (pages 64–74) to discuss further the Regional Directional Transfer Limit between the Midwest and Delta regions and associated transmission limitations. Section V.a. also includes more discussion on the limitations within the context of recent weather events, including the cold weather bulk electric system event in January 2018, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022 (pages 56–58).

The Department recognizes that PJM was able to export electricity to its neighbors to aid in grid reliability during the February 2021 winter cold event. The cited reports' findings of a lack of interregional interconnections limited the abilities of some regions to maintain reliability during this event are retained in the final Study version. The Department did add the important clarification raised by the commenters that within-region transmission or distribution system upgrades may be necessary to support any given expansion in interregional transmission in a couple of instances. In *Section V.a. Reliability and Resilience* the Department added a reference to a PJM report stating: "In other words, because of the complex nature of transmission flows, interregional transfer capability can be limited by insufficient transmission capacity internal to a region (PJM 2023d)," (page 58). In *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* the Department added: "Additionally, any portion of these

transmission system additions may require associated distribution or transmission system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds. These downstream analyses are critical to the transmission planning process to ensure reliable operation of the grid but are out of scope for the analysis presented here," (page 114).

While important, data sharing and interoperability standards are outside the scope of this effort and are not included in the final Needs Study.

The Department maintains that because the Needs Study is a review of previously performed studies and does not include any new system modeling, the inclusion of additional state resource projections (outside of those already included in the works reviewed), cost analyses of specific projects, and coordination with planning entities in modeling exercises are not within scope of this effort.

## 1.7. Stakeholder Engagement

As DOE finalizes the Needs Study and plans for corridor designation, EDF encourages DOE to develop a plan for engaging with potentially impacted and historically disadvantaged communities. While EDF appreciates DOE's stakeholder engagement in the preparation of the draft Study, it argues that DOE should carry out stakeholder engagement beyond the statutory minimum before the final Study is published. Particularly, EDF requests that DOE engage with nongovernmental organizations with transmission knowledge, energy justice organizations, and potentially impacted communities. EDF asserts that this will lay the groundwork for relationships with community members that will be necessary in the corridor designation process. The Blue Lake Rancheria Tribe adds that Tribal nations need to be included in transmission planning efforts related to offshore wind (OSW) integration. Specifically, it argues that planners must consider the energy and infrastructure needs of Tribal nations and minimize impacts to Tribal land.

The Advanced Energy Group (AEG) emphasizes the need to educate stakeholders on the need for and benefit of transmission expansion. AEG recommends that this education aligns with the priorities of impacted communities and addresses how transmission can support wealth creation, energy cost burden, and public health concerns. Additionally, AEG urges transmission planners to listen to communities and their experiences and compensate stakeholders for their contributions.

Keryn Newman argues that the Needs Study does not include adequate consultation with landowners, whom Newman identifies as those who will most experience the devastating impacts of transmission development. Newman argues that the Study identifies landowner concerns as a barrier to transmission deployment but does not bother to consult these "barriers" or to devise solutions to mitigate their concerns. For this very reason, Newman also objects to the FERC *Report on Barriers and Opportunities for High Voltage Transmission*, which

is cited in the Needs Study.[14] Additionally, Newman argues that landowner interests should be represented on DOE's Technical Review Committee.

CEBA encourages DOE to solicit additional feedback from regional, state, and Tribal entities regarding the Needs Study and possible future improvements. Additionally, it encourages DOE to consult with large energy customers to ensure the Study's projections of load and clean energy demand are consistent with their internal projections. CEBA writes that this step could improve the Study's utility and credibility for industry and government purposes. DCC also recommends engaging with large commercial and industrial customers for future studies. It encourages DOE to convene large energy customers, including representatives from the data center industry, before future publications ensure data are most recent.

SERTP Sponsors encourage DOE to consult with transmission planning entities, like Eastern Interconnection Planning Collaborative (EIPC), before acting on the findings of the Needs Study, which the organization deems as hypothetical transmission needs. SERTP Sponsors urge DOE to consult with planners on their projections of load, resources, and transmission costs, arguing that this information would allow for a more meaningful and holistic assessment of transmission value and help DOE to identify the regions where transmission is most needed.

### Department Response

In response to comments from parties requesting additional, targeted stakeholder and Tribal outreach and continued stakeholder engagement, the Department has made additional efforts to engage with entities beyond the Department's consultation with states, Tribes, and regional entities pursuant to Section 216(a) of the FPA, as amended (16 U.S.C. §824p(a)(1)). The Department has continued to accept meeting requests from commenting and interested parties to discuss draft Study findings.

Further, the Department has created regional and national fact sheets to be appended to the final Study and released concurrently to help make Study findings more accessible. The Department hopes the final Needs Study will be used as an educational tool to engage communities in discussion about grid needs. Departmental communications on final Study findings are a tool to solicit additional feedback from stakeholders on what future iterations of the Needs Study should entail.

The Department agrees with commenters that landowner, community, stakeholder, and Tribal engagement is imperative. The Department added *Section V.e. Siting and Land Use Considerations* (pages 95–108) to the final Study on subjects of unique interest to the communities. This section contains discussion of best practices for developers in engaging with landowners and other affected parties.

Additionally, the Department added a new subsection on specific Tribal energy needs to *Section V.c. Generation and Demand Changes*. This subsection (pages 74–89) includes recently

[14] Federal Energy Regulatory Commission. 2020. Report on Barriers and Opportunities for High Voltage Transmission. Available at https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

collected data by the Department's Office of Indian Energy which describe electricity access on Tribal lands.

## 1.8. Future DOE Action

The Center for Biological Diversity argues that DOE has failed to meet the statutory requirements in previous grid studies and urges DOE to continue the draft Study's efforts. The Center states that Pub Law 109-58 Section 1221 mandates DOE to conduct grid studies every 3 years, and claims DOE has rarely complied. It urges DOE to keep this Needs Study on track to finalize as soon as possible. Furthermore, it urges DOE to adequately address each of the Study requirements detailed in the IIJA.

CEBA suggests that DOE communicate, either directly in the Needs Study or on its website, the iterative nature of the report. Specifically, CEBA requests information on the lessons DOE learned from this iteration, as well as any suggested future studies.

While CEBA understands there are barriers to data collection, specifically in non-RTO regions, it emphasizes that this deficiency hinders the Study and its ability to assess transmission need. It encourages DOE to improve data collection in future iterations of the Needs Study and suggests that DOE organize working groups to brainstorm methods to do so.

ITC asks DOE to support existing planning efforts such as the LRTP and MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study. National Grid describes its potential project, Twin States Clean Energy Link, which would connect New England to Québec, Canada. It requests DOE's support efforts to increase interregional transfer capabilities, financially and in advocacy.

A couple of commenters discuss DOE's expected NTP Study. CEBA requests clarification on how the Needs Study and NTP Study are related and specifically asks whether the NTP Study will identify solutions to the needs identified in the Needs Study.

EDF offers several suggestions for the NTP Study, itemized below:

- The NTP Study should have a time horizon of at least 20 years to account for the long lead time of transmission development, long-term decarbonization goals, and grid modernization efforts. Furthermore, the NTP Study should consult existing federal, regional, and state planning processes to ensure it accounts for impacts of planned, long-term system evolution.
- The NTP Study should consider a wide range of scenarios that reflect various future grids. EDF suggests DOE look to existing policies and actions at the state, federal, and regional level to design these scenarios. It also urges DOE to account for the impacts of recent climate legislation and to consult with local resources, such as New York Independent System Operator's (NYISO's) annual *Load and Capacity Data Report* (Gold Book),[15] to define energy demand scenarios. Also, EDF notes that extreme weather

[15] New York Independent System Operator. 2022. 2022 Load and Capacity Data Report. Available at https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf.

events are increasingly common. Accordingly, they state that billion-dollar weather events and climate disasters should be assumed in all scenarios.

- The NTP Study should include a thorough analysis of non-wire alternatives and grid-enhancing technologies (GETs), in which they are not treated as an outlier, but instead entirely incorporated into the NTP Study's assessment.
- The NTP Study should include stakeholder engagement that is at least as inclusive as what was done in preparation for the Needs Study. Additionally, EDF urges DOE to develop a strategy to meaningfully collaborate with energy justice, environmental justice, Tribal, historically disadvantaged, and low-income communities. EDF also expresses support for DOE's suggestion that studies should prioritize renewable energy development in regions experiencing fossil dependence, energy burden, and environmental or socioeconomic vulnerabilities and that transmission should work to mitigate harms to those experiencing high energy burden, frequent or long-duration outages, and high levels of environmental hazards.

AE notes that grid technologies and transmission needs are changing rapidly and asserts that planning processes must become more dynamic and responsive to keep pace. It explains that new grid technologies, such as storage and demand response, can make long-term transmission planning more susceptible to "costly inefficiencies, as the rapidly evolving grid makes some approved transmission projects obsolete before they are even completed." AE expresses support for long-term planning efforts but suggests that long lead time projects are reassessed every 3 years, to ensure assessments reflect the changing realities of the grid.

One individual, Vijayasekar Rajsekar from Institute of Electrical and Electronics Engineers and Pacific Gas and Electric Company,[16] suggests that DOE assess the feasibility of interconnecting the U.S. grid to create a "National Grid" that mitigates reliability concerns and reduces the frequency of blackouts.

### Department Response

The Department appreciates comments regarding future DOE action related to the Needs Study. The Department has determined addressing these comments is currently beyond the scope of the 2023 Study.

[16] Rajsekar commented on their own behalf, not on behalf of Institute of Electrical and Electronics Engineers and Pacific Gas and Electric Company.

# 2. Gaps and Additional Resources

## 2.1. Legislation and Regulations

AMPUA and IEDA urge DOE to reference FERC Docket No. ER21-1790-003 in the Needs Study. They explain that the Southwest is heavily reliant on transmission from California and FERC Docket No. ER21-1790-003 authorizes CAISO to prioritize California's energy demands over those in the Southwest. Given this, they argue that the Southwest is vulnerable to supply shortages. AMPUA and IEDA encourage DOE to consider this regulation and to include the Southwest's need to reduce dependency on CAISO's transmission infrastructure in the Needs Study.

The Columbia River Treaty Group recommends that DOE review provisions in the IIJA regarding the future of the Canadian Entitlement. It argues that the 1964 Columbia River Treaty, which mandates the United States provide Canada a portion of the power benefit created by Canadian storage dams, is outdated and exceeds what should be returned to Canada. The Columbia River Treaty Group explains that the IIJA includes provisions to rebalance and modernize the Treaty and urges DOE to consider this negotiation in the Study.

Con Edison cites the Climate Leadership and Community Protection Act (CLCPA) as ambitious state legislation that requires "70 percent renewable energy by 2030, 100 percent carbon-free electricity by 2040, and 85 percent economy-wide decarbonization from 1990 levels by 2050. This includes goals of 6,000 megawatts of distributed solar installed by 2025, 3,000 MW of storage installed by 2030, and 9,000 MW of offshore wind installed by 2035." Con Edison clarifies that meeting CLCPA mandates will require transmission expansion in New York, especially to integrate OSW. Hydro-Québec echoes this sentiment, urging DOE to consider New York and New England's ambitious climate legislation. It cites the CLCPA in New York and several clean energy and emission reduction targets in New England.

Similarly, Seattle City Light informs DOE of Washington's passage of the Clean Energy Transformation Act (CETA), which will make previous state projections obsolete. While CETA impacts have not been fully studied yet, it shares that a study is underway by NorthernGrid, which may reveal the legislation's impact on the transmission system.

PIOs suggests that the Needs Study consider the IRA and U.S. Environmental Protection Agency's (EPA) recent proposed rule, *Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicle*. They cite multiple BloombergNEF articles, which project significant increases in renewable energy, residential electrification, and electric vehicle deployment driven by policy efforts. Accordingly, PIOs encourage DOE to adopt high load and high clean energy assumptions as the Needs Study's base case. Similarly, National Grid emphasizes that the IRA will further accelerate the Northeast region's decarbonization efforts and increase electrification, helping serve as a model for the rest of the country on the impact of the legislation on states' clean energy policies.

PSEG and EEI request that DOE acknowledges FERC's role in transmission planning and investment. EEI objects to the draft Study's statement that "many existing transmission planning processes 'are primarily focused on compliance with NERC and local reliability

standards with very limited scopes and planning horizons,'" arguing that it fails to acknowledge FERC's recently proposed transmission planning reforms. EEI cites FERC's Notice of Proposed Rulemaking to change regional transmission planning and cost allocation requirements and notes that such reforms will encourage efficient, cost-effective transmission investment. EEI urges DOE to acknowledge FERC's role in planning reform in the Needs Study. Similarly, PSEG argues that regulatory certainty is crucial to addressing transmission need. It explains that FERC's proposal to remove the RTO adder incentive is a policy that discourages transmission investment.

ERCOT suggests that DOE review recent Public Utility Commission of Texas (PUCT) reforms, stating that the Needs Study's continued reliance on 2021 data contributes to an overestimate of the benefits of increased interregional transmission connections between ERCOT and neighboring regions. ERCOT explains that following the February 2021 winter storm, PUCT adopted reforms to reduce the likelihood and the financial impact of a future such event. Specifically, ERCOT cites the adoption of Tex. Util. Code § 35.0021, Tex. Nat. Res. Code § 86.044, 16 Tex. Admin. Code § 25.55, Tex. Admin. Code § 25.52(h), and Tex. Util. Code § 38.201, which mandate several reliability, resiliency, and planning efforts. In addition, ERCOT references ongoing market reforms, which will cumulatively reduce ERCOT's need for interregional transmission capacity.

### Department Response

The Department focused analysis of transmission need on physical limitations of the system and not jurisdictional or regulatory limitations. For this reason, FERC authorities and international treaties were considered out of scope.

Several commenters note recent climate legislation for particular regions and urge the Department to consider implications from new legislation, specific to projected clean energy generation and load changes. The Department did reorganize information in the draft Study and include additional context in *Section V.c. Generation and Demand Changes* to highlight that a) new transmission will be needed to access many clean energy resources (pages 74–79) and b) load growth will require more transmission (pages 87 and 89). These changes include references to 16 additional industry reports not included in the draft Study.

Similarly, PIOs urge the Department to adopt the high load and high clean energy case as the final Study's base case considering the passage of the IRA and EPA's recent proposed vehicle emissions standards. In response to these comments and those referencing recent state climate legislation, the Department states in both the Executive Summary and in discussion of capacity expansion modeling results in Section VI that scenarios including high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios. Results of this scenario group were also highlighted in Figures ES-5 and ES-6 (pages ix–x) in the Executive Summary of the final Study, whereas only results of the moderate load and high clean energy growth scenario group were highlighted in the draft Study. The Department includes additional context regarding the relevance of the high load and high clean energy scenario groups throughout *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* (notably, pages 119, 143–144). Further, the Department includes

a reference to a recently published National Renewable Energy Laboratory (NREL) Study on the Impacts of the IRA on the U.S. power system in *Section VI.a. Included Studies and Scenarios* (page 118).

In response to commenter objections to the Department's characterization of existing planning efforts and recommendations to acknowledge FERC's role in transmission planning and investment, the Department has removed the statement highlighted by EEI and added further clarification in Section I of the final Study (pages 1–2) that this Study will inform existing industry-led transmission planning processes conducted in accordance with FERC regulations and policies. Notably, the Department has added the clarification that "[t]ransmission planning is predominantly conducted today by local utilities, who plan for transmission needs on their respective transmission systems, and regional planning authorities formed under FERC Order 1000, which plan for regional needs and identify regional transmission projects that are more efficient or cost-effective solutions" (page 2).

The Department maintains that the citations to outages and interregional transfer limitations experienced by ERCOT in the February 2021 winter storm are still relevant and these have been maintained in the final Study. Increased interregional transfer capability is, of course, only one of many solutions that would help prevent similar outages in the future. The Department further clarifies this in the relevant passage of *Section V.a. Reliability and Resilience* by noting other recommended reforms that are unrelated to transmission (page 63).

## 2.2. Studies and Reports

Approximately 19 commenters suggest additional studies and reports for DOE to consider and revisit before finalizing the Needs Study.

### Low-Cost and Reliable Transmission Service

Many commenters like ACORE, AE, ITC, PIOs, Xcel Energy, Vijayasekar Rajsekar, and PJM suggest incorporating the following studies and resources into the Study to enhance the analysis of transmission benefits and provide guidance on low-cost solutions and best practices for ensuring reliable transmission service:

- NREL, *Interconnections Seam Study*[17]
- Grid Strategies, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long-Range Transmission Planning*[18]

[17] National Renewable Energy Laboratory. 2020. The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study. Available at https://www.nrel.gov/docs/fy21osti/76850.pdf.

[18] Gramlich R. 2022. Enabling Low-Cost Clean Energy and Reliable Service through Better Transmission Benefits Analysis – A Case Study of Miso's Long Range Transmission Planning. Available at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

- Telos Energy, *Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force*[19]
- Brown & Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System*[20]
- Grid North Partners, *The CapX2050 Transmission Vision Report*
- Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value using Locational Marginal Prices*[21]
- PJM, *Interregional Transfer Capability Proceeding*[22,23]
- MISO, *Long-Range Transmission Planning Process*
- MISO-SPP, *Joint Targeted Interconnection Queue Study*

### Technology

AE and the WATT Coalition highlight studies that support the expansion and benefits of various transmission technologies. They propose that DOE incorporate The Brattle Group's 2021 *Unlocking the Queue with Grid-Enhancing Technologies*[24] study to further highlight how GETs can significantly increase existing grid capacity. Additionally, the WATT Coalition points out that insufficient attention is given to the increasing utility of GET investments in the Study and provides DOE with case studies showcasing the deployment of GETs in the United States.[25] The

[19] Energy Systems Integration Group. 2022. Multi-Value Transmission Planning for a Clean Energy Future. Available at https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

[20] Brown P, Botterud A. 2021. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System, p. 115. Available at https://www.sciencedirect.com/science/article/pii/S2542435120305572.

[21] Lawrence Berkeley National Laboratory. 2022. Empirical Estimates of Transmission Value using Locational Marginal Prices, p. 3. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

[22] Federal Energy Regulatory Commission. 2022. Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements held December 5–6, 2022, Docket No. AD23-3-000. Available at https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

[23] Federal Energy Regulatory Commission. 2023. Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Notice Requesting Post-Workshop Comments, Docket No. AD23-3-000. Available at https://ferc.gov/media/notice-requesting-post-workshop-comments-docket-no-ad23-3-000.

[24] Tsuchida T, Ross S, and Bigelow A. 2021. Unlocking the Queue with Grid-Enhancing Technologies. Available at https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

[25] Available at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwatt-transmission.org%2Fwp-content%2Fuploads%2F2023%2F04%2FUS-GETs-Case-Studies.xlsx&wdOrigin=BROWSELINK.

WATT Coalition also suggests that DOE reference a 2019 paper[26] to address barriers hindering the optimal and effective utilization of existing and future transmission infrastructure.

### Offshore

ACORE, PIOs, and SPIGs request DOE include the following relevant studies regarding the benefits of OSW integration:

- The Brattle Group, *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goal*[27]
- Smith et al., *Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets*[28]
- DOE, *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis*[29]

Given that the *Atlantic Offshore Wind Transmission Study* anticipates a significant amount of OSW in the Northeast and discusses the associated challenges, National Grid recommends that DOE consider the interaction between NREL's study and the results of the Needs Study, particularly regarding interregional transfers. Additionally, PSEG suggests that DOE update the Study to incorporate the 40 recommendations included in the updated *Atlantic Offshore Wind Transmission Action Plan*.

### Extreme Weather Events

Many commenters provide materials to better capture extreme weather events in the Study.

CEBA notes that the Study may potentially underestimate transmission needs, as it fails to consider the impact of recent events, such as Winter Storm Elliott. ACORE and SPIGs recommend including Grid Strategies' *The Value of Transmission During Winter Storm Elliott*[30] to showcase the benefits of interregional transmission during extreme weather events. Specifically, SREA suggests that DOE incorporate Grid Strategies' approach in determining the value of transmission. SREA mentions that Grid Strategies utilizes wholesale power prices at the

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[26] Tsuchida T, and Gramlich R. 2019. Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives. Available at https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf.

[27] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[28] Smith K, Lenney S, Marsden O, Kates-Garnick B, Stanković A, Hines E. 2021. Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets. Available at https://createsolutions.tufts.edu/wp-content/uploads/2021/08/OSW-Transmission-and-Grid-NE.pdf.

[29] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis. Available at https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.2021.

[30] Goggin M, and Zimmerman Z. 2023. The Value of Transmission During Winter Storm Elliott. Available at https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

interfaces between TVA (Tennessee Valley Authority) and Duke Energy with MISO and PJM, then applies a value of lost load (VOLL) of $9,000 to determine the value of transmission, which factors in the value of transmission during extreme weather events.

For additional reading, Vijayasekar Rajsekar suggests that DOE consider ERCOT's letter to Members of the Texas Senate and the Texas House of Representatives regarding generator outages during the cold weather event in February 2021.[31] Additionally, Rajsekar provides *Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011, Causes and Recommendations*.[32]

### Other Topics

TDI New England disagrees with the Needs Study's reference to Brinkman et al. in Section VI.d., explaining that the statement about significant international transfer capacities between Canada and New York and New England not arising until 2040 is incorrect. TDI New England points out that New England Clean Power Link is a fully permitted transmission project, situated to commence and complete construction in a timely manner, which will enable considerable international transfer capacities well before 2040. Similarly, NYTOs disagree with DOE's statement, as they expect Champlain Hudson Power Express (CHPE) to be operational by spring of 2026.

The Blue Lake Rancheria Tribe suggests DOE update outdated references to clean energy and economic potential statistics. For instance, markets with recent increases in energy costs and constraints have the potential to develop significant amounts of clean energy as both economic enterprises and economy-enabling infrastructure.

An individual commenter, William Driscoll, proposes that DOE add a discussion on the benefits of flexible demand, citing two of his published stories: *Real-time pricing that balances renewables could save $33 billion per year, study finds*[33] and *California rulemaking to pursue demand flexibility through dynamic pricing*.[34]

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[31] Electric Reliability Council of Texas. 2021. ERCOT letter to Members of the Texas Senate and the Texas House of Representatives regarding Generator outages during February 2021 cold weather event, dated March 4, 2021. Available at https://www.ercot.com/files/docs/2021/03/04/ERCOT_Letter_Re_Feb_2021_Generator_Outages.pdf.

[32] Staff of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. 2011. Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011, Causes and Recommendations. Available at https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf.

[33] Driscoll W. 2022. Real-time Pricing that Balances Renewables Could Save $33 Billion per Year, Study Finds. Available at https://pv-magazine-usa.com/2022/06/15/real-time-pricing-that-balances-renewables-could-save-33-billion-per-year-study-finds/#:~:text=Markets-,Real%2Dtime%20pricing%20that%20balances%20renewables%20could%20save%20%2433%20billion,bills%2010%25%20to%2017%25.

[34] Driscoll W. 2022. California Rulemaking to Pursue Demand Flexibility through Dynamic Pricing. Available at https://pv-magazine-usa.com/2022/07/22/california-rulemaking-to-pursue-demand-flexibility-through-dynamic-pricing/#:~:text=Demand%20flexibility%20would%20allow%20consumers,%E2%80%9Csending%20prices%20to%20devices.%E2%80%9D.

Gallatin Power recommends reviewing the draft *CAISO 2022–2023 Transmission Plan* to highlight constraints on Paths 46 and 66.

Xcel Energy is concerned that DOE did not review reports developed by utilities, such as Grid North Partners' *The CapX2050 Transmission Vision Report*, suggested above.

Juneau Hydropower, Inc. (JHI) advocates for the inclusion of DOE's *Hydropower Vision Chapter 3, Assessment of National Hydropower Potential*.[35] JHI elaborates that it is important to recognize that water is much denser than air and can serve as a powerful energy source for the country and help meet the Nation's economic, energy, and national security objectives.

Vijayasekar Rajsekar includes a list of further reading suggestions for DOE, including *The U.S. May Finally Get a Unified Power Grid*[36] by Kumagai, J. and the *Continental Europe Synchronous Area Separation on 8 January 2021*[37] by European Network of Transmission System Operators for Electricity (ENTSO-E).

SPIGs recommend that DOE consider its Initial Comments in Response to FERC Notice of Proposed Rulemaking in Docket No. RM21-17-000[38] for further insights.

### Department Response

Whereas Section V of the draft Study references over 50 different industry reports published in the past 5 years, the final version references more than 100 recent reports to highlight the historical and anticipated drivers of transmission needs, the multiple benefits that additional transmission infrastructure can provide to consumers, and the challenges of expanding the Nation's electric transmission infrastructure. A complete list of the reports reviewed for incorporation into Section V of the final Needs Study are listed in Table S-4 of the accompanying Supplemental Material document (pages 13–24). The Department notes that several of the studies referenced by commenters were already included in the draft Study. Many of the studies added to Section V of the final Study were specifically suggested by commenters, which include, but are not limited to:

- NREL, *Interconnections Seam Study*
- Grid North Partners, *The CapX2050 Transmission Vision Report*
- MISO, *Long-Range Transmission Planning Process*
- CAISO, *2022–2023 Transmission Plan*

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[35] U.S. Department of Energy. 2016. Hydropower Vision Chapter 3, Assessment of National Hydropower Potential. Available at https://www.energy.gov/node/1922621/.

[36] Kumagai J. 2015. The U.S. May Finally Get a Unified Power Grid (*IEEE Spectrum Magazine*). Available at https://ieeexplore.ieee.org/document/7367461.

[37] European Network of Transmission System Operators for Electricity. 2021. Continental Europe Synchronous Area Separation on 8 January 2021, Interim Report. Available at https://eepublicdownloads.azureedge.net/clean-documents/Publications/Position%20papers%20and%20reports/entso-e_CESysSep_interim_report_210225.pdf.

[38] Southeast Public Interest Groups. Initial Comments in Response to Federal Energy Regulatory Commission Notice of Proposed Rulemaking in Docket No. RM21-17-000.

- The Brattle Group, *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goal*
- DOE, *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis*
- Grid Strategies, *The Value of Transmission During Winter Storm Elliott*

In response to the Blue Lake Rancheria Tribe suggestion for DOE to update outdated references to clean energy and economic potential statistics on Tribal lands, the Department has added an additional subsection (pages 84–86) to provide more context surrounding unique Tribal energy and transmission needs. The subsection addition includes preliminary results from a Department-conducted survey of Tribal access to reliable electricity as directed by the Consolidated Appropriations Act, 2021 (pages 84–85).

Many commenters suggested news articles for inclusion in the final Study. Except in rare circumstances for which a substitute reference could not be found, these articles were omitted from review and instead a published report or industry reference on the suggested topic was used. Highly technical journal publications that are not accessible to the wider public were similarly omitted from this analysis.

## 2.3. Data and Assumptions

Approximately 35 commenters suggest changes to data and assumptions used in the Study.

Seattle City Light finds that the transmission challenges related to the Canadian Entitlement Return and other flows between British Columbia and the Pacific Northwest have not been considered in the Study and stresses the importance of recognizing the need for solutions that address the transmission issues between Canada and the Northwest. Seattle City Light states that British Columbia also supplies electricity to California for many hours of the year and dealing with regional power flows have been challenging since the early 2000s when the first Puget Sound Area – Northern Intertie curtailments occurred.

Alaska Energy Authority (AEA), National Hydropower Association (NHA), and JHI urge DOE to include Alaska in the Study. As JHI notes, while Alaska aims to reduce energy costs by transitioning to renewable energy sources and improving transmission reliability, the state's transmission infrastructure is severely lacking compared with the contiguous United States. NHA suggests including an Alaska appendix to address the state's significant transmission needs, considering its unique characteristics. JHI points out that if the Study's purpose is limited in scope, then DOE should create an Alaska Annex. NHA suggests the Study recognize Alaska's potential to export hydropower to the Yukon or British Columbia through future transmission links. However, NHA notes hydropower development requires markets and transmission infrastructure, and high transmission costs can hinder viability without federal or other subsidies. Moreover, JHI states that federal authorization for a Southeast Alaska Intertie in 2000 to interconnect the region of the state with high-voltage transmission lines have still not yet been appropriated by Congress. It notes that the Alaska Railbelt region also requires enhancements to alleviate congestion, enhance redundancy, and accommodate current and future electricity generation. It also believes it is crucial to view Alaska's transmission needs from an environmental and social justice perspective, in addition to economic and national security.

DCC mentions that the data center industry has experienced the impact of inaccurate or underestimated forecasts of energy demand growth drivers. It stresses the importance of ensuring that load forecasts consider a variety of factors that drive demand, like electric vehicle growth, electrification, and other industry trends. Similarly, one individual, Martyn Roetter, adds that it is unclear whether the Study has thoroughly evaluated the overall demand for clean electricity, including the potential load from indirect uses like green hydrogen and low carbon fuel production, and the potential load from carbon removal systems.

Referring to its recent study, the *Energy Transition Report*, which examines the impact of industry trends and federal decarbonization policies in the PJM Region, PJM urges DOE to consider four trends that pose reliability risks during this transition:

- Electricity demand is increasing due to electrification and the growth of data centers in the region.
- Thermal generators are retiring quickly due to government and private sector policies and economic factors.
- Retirements may outpace the construction of new resources, with potential long-term consequences.
- PJM's interconnection queue primarily consists of intermittent and limited-duration resources, which require more capacity to replace thermal generation.

Econwerks states that the report fails to mention energy efficiency and does not sufficiently discuss demand-side management. Econwerks also indicates that there is no mention of the use of real-time pricing to ration demand, load modifying programs, or VOLL in the draft Study.

Utah Public Lands Coordinating Office mentions that the Study does not consider major transmission lines like Energy Gateway South and TransWest, nor does it address the need for substations and supporting infrastructure to accommodate the growing use of solar, wind, and geothermal energy. Xcel Energy notes there are ongoing efforts that might address some of the conclusions from the Study. It recommends considering the current planning assessments, known projects, and depicting the outcomes as a gap and needs assessment. It asks for clearer understanding of how these plans align with the analyzed scenarios to determine realistic paths forward. It offers regional transmission plans, IRPs, and other analyses conducted by utilities that could provide better information for comparing these plans.

CEBA, SPIGs, and SREA all discuss the need for additional data in the Needs Study. CEBA recognizes that the lack of data availability on local, regional, and interregional congestion and capacity constraints, specifically in non-RTO regions in the West and the Southeast, poses challenges to the comprehensive nature of the Study. CEBA encourages DOE to improve data collection for future iterations of the Needs Study by leveraging its technical and convening capabilities to set up working groups to address concerns and barriers. SPIGs supports DOE's interest in using quantitative measures to identify existing transmission needs. As evident from the gaps in draft Study Figures IV-4 through IV-6, SPIGs highlight the limitations that are due to the absence of an independent wholesale energy market and the associated price transparency in the Southeast. SPIGs also observe that the primary metric used in the Study to evaluate needs—market price differentials—excludes the Southeast entirely. SREA encourages DOE to

work with SERTP utilities to obtain nodal data so more specific transmission analysis can be conducted.

ERCOT argues that DOE fails to fully account for data that may skew overall historical trends. For example, ERCOT questions DOE's use of 2021 price data in its analysis since it includes Winter Storm Uri, which ERCOT argues is a statistically outlying event. Although ERCOT notes that the Study tries to reduce its emphasis on 2021 data by introducing data from additional time periods, ERCOT insists that continued reliance on it still overestimates the benefits of increased interregional transmission connections between ERCOT and other regions. ERCOT additionally notes that Texas regulators have enacted reforms since the storm that would reasonably be expected to reduce the likelihood and the financial impact of a similar event.

Con Edison does not oppose the Needs Study's suggested GW increase in the interregional transfer capacity assessment but requests additional transparency regarding DOE's data to confirm whether it is up to date. Con Edison notes that it is important to confirm the most up-to-date information, as it will ensure the accurate assessment of transmission needs.

Several commenters emphasize the need to consider resilience in regional planning. Grid United recommends that DOE continue exploring methodologies that can assess the impact of extreme weather events. One approach it mentions is to conduct Loss of Load Expectation studies, which involve more advanced modeling to account for weather volatility. It indicates that qualitative assessment of past extreme weather events, like storms Uri and Elliott and the California heatwave, could also be conducted if Loss of Load Expectation studies are too quantitatively rigorous. PJM notes several emerging system conditions that already present challenges to reliable system operations, including cyberattacks and shifts in the generation fleet. In assessing needs for the Southeast, SREA highlights the importance of considering any relevant data from the joint FERC/NERC inquiry into Winter Storm Elliott, initiated on December 28, 2022.

Some commenters point to the absence of state-level data or assumptions. Utah Public Lands Coordinating Office mentions that the national assessment did not consider the state-level studies. Utah Public Lands Coordinating Office cites studies like the *Utah Transmission Study* that highlight potential capacity issues as Utah's population grows and electricity demand increases, especially during extreme temperatures and studies that conclude that Utah would not gain many benefits from joining ISO/RTO because of its already low electricity prices and reliable grid. Utah Public Lands Coordinating Office also emphasizes that there are concerns about increasing energy costs when moving east from Utah, like seen in draft Study Figure IV-6, suggesting a need for new infrastructure to meet future energy needs in those areas. The Utah Public Lands Coordinating Office encourages DOE to consider the goals, objectives, and policies of energy solutions and align them with those at the state and local planning levels, which will help avoid legal conflicts and speed up the completion of energy projects.

SERTP Sponsors suggest the Study would benefit from including more information from state-regulated processes, particularly regarding the bottom-line impact on customers. They indicate the FPA reserves exclusive authority for the states to regulate facilities used for electricity generation, which includes making decisions about planning and resources for utilities.

Therefore, it is unclear to them why the Study independently makes assumptions about load and resources based on various studies as opposed to using state-determined resource decisions. SERTP Sponsors recommend that DOE collaborates with the EIPC to include the resource decisions made by states in their planning efforts.

Econwerks and Keryn Newman raise concerns regarding the report's presumption that all congestion can be addressed and eliminated. Econwerks suggests that the Study should differentiate between economically justified expansion of renewable technologies and their impact on the grid. Econwerks cautions against treating congestion as the sole driver for transmission expansion, as it could lead to predetermined conclusions and excessive infrastructure development. Monitoring Analytics notes that because the geographic distribution of congestion is dynamic, constructing transmission to address a specific congestion pattern does not make sense unless the technology can be easily moved to new locations as conditions change.

Xcel Energy provides suggestions for improving discussions on curtailment, including acknowledging additional reasons for why resources may be curtailed outside of transmission constraints and recognizing the value gained from reduced curtailment. It argues that allowing some level of curtailment in a higher variable energy future may be more cost-effective than efforts to eliminate curtailment entirely. Xcel also references MISO's RIIA, which indicates that renewable resources operating below maximum capacity can improve system stability. Finally, Xcel Energy calls for additional context on the cost-benefit balance of addressing certain transmission constraints as other constraints are mitigated.

### Department Response

The Department focused analysis of transmission need on physical limitations of the system and not jurisdictional or regulatory limitations. For this reason, international agreements were considered out of scope.

In response to commenters requesting more information regarding the need for transmission in Alaska, the Department has incorporated both Alaska and Hawaii into the final Study. Historic Alaskan transmission installations[39] were incorporated into *Section IV.a. Historical Transmission Investments* (pages 20–31). Additional discussion of transmission needs of both states can be found throughout *Section V. Current and Future Need Assessment and Identification of Transmission Benefits through Review of Existing Studies*. Eleven additional references to the Alaskan or Hawaiian power grids were reviewed for inclusion in this section, which can be viewed in Table S-4 of the accompanying Supplemental Material document (pages 13–24). Capacity expansion modeling data are limited for Alaska and Hawaii. As a result, neither Alaska nor Hawaii was incorporated into the analysis in *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling*.

[39] Historic Hawaiian transmission investments were not intentionally omitted from this section, but no transmission investments that met the threshold for inclusion in the analysis were identified in Hawaii.

Various commenters suggested the draft Study underestimates energy demand growth drivers or suggested a high load growth and high clean energy penetration scenario would be a more appropriate base case considering the passage of IRA and IIJA. In response, the Department has expanded Section V.g. of the draft Study to encompass more than just implications from and factors leading to increased electrification to include more discussion. The subsection, now included in pages 87 and 89 under *Section V.c. Generation and Demand Changes*, discusses additional factors outside of increased end-use electrification that would serve to increase demand, including emerging industries such as data centers, chemical production, hydrogen production, and direct air capture, among other drivers. Several transmission planning reports that identify the emergence of high-demand industrial growth were also added to the report. See Department Response in Section 4.4 of this comment synthesis for a discussion of how increased demand due to hydrogen production and carbon dioxide removal is considered in Section VI.

Further, as discussed in Section 2.1 above of this comment synthesis, the Department includes additional context regarding the relevance of the high load and high clean energy capacity expansion scenario group included in the final Study. Findings for this scenario group are highlighted alongside those for the moderate load and high clean energy scenario groups in study graphics, including Figures ES-5 and ES-6 (pages ix–x) of the Executive Summary. The Department also states in both the Executive Summary and in discussion of capacity expansion modeling results in Section VI that scenarios that include high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios (pages 118–119).

The Department also addresses suggestions from commenters to provide more information with respect to the needs of certain regions and states. In response to PJM's comment requesting more nuanced discussion about reliability concerns given a shifting generation mix, the Department has incorporated suggested references and expanded discussion of reliability needs in *Section V.a. Reliability and Resilience*, notably on pages 54–55, 62–63, 87, and 89. The Department additionally included five PJM references in the final Study that were not included in the draft Study.

While important to power sector evolution, the Department deemed demand-side solutions, including energy efficiency, to be outside the scope of this National Transmission Needs Study. The Department does acknowledge the importance of demand-side solutions in the final Study, however. In *Section V.b. Market Price Differentials* the Department states "[o]ther strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices. The specific solutions that work for each locality might be unique to that community," (page 34). Additionally, the Department does briefly discuss the role of energy efficiency in power sector development in *Section V.c. Generation and Demand Changes*, notably on page 87. Demand response solutions are also identified as a potential alternative transmission solution on page 90.

Similarly, market-based solutions were deemed out of scope except as they impact the transmission system. The intersection of markets and transmission congestion are discussed

throughout Section V, and at length in *Section V.b. Regional Congestion and Constraints* (pages 64–74).

The Department emphasizes that the Needs Study is not meant to identify particular solutions in *Section I. Introduction*. As such, the Department made a general practice of not identifying specific transmission projects in the final Study, and therefore projects referenced by commenters like Utah Public Lands Coordinating Office and Xcel Energy are omitted from the final Study. Further, the Department uses *transmission* in a technology-agnostic way throughout the final Study, whereby individual transmission elements necessary for system function, such as substations, are not called out specifically.

The Department acknowledges that lack of data access makes determining transmission need difficult in some regions, particularly in the non-RTO/ISO regions like the Southeast and Florida. Absence of data does not necessarily indicate that there is no need for new transmission. The Department has added several acknowledgments of this point by stating throughout the Study that the absence of data does not necessarily indicate that there is no need for new transmission. This acknowledgment is notable on all summary figures, including Figure ES-7 (page xi). The Department draws on several different analyses to determine need, not just the market price differentials analysis, a point that was additionally made clear in the summary figures.

ERCOT notes the discussion of price data in ERCOT and SPP includes data from 2021 Winter Storm Uri, an event that is an outlier among historical data. The Department believes retaining analysis of this event is important given the immense implications it had on the power sector and electricity consumers. The Department does include additional discussion in *Section IV.b. Market Price Differentials* of the final Study (pages 39–42) describing how extreme events, such as Winter Storms Uri and Elliott, can produce price spikes in affected areas. This section also analyzes the portion of total transmission congestion value attributable to high-value hours or extreme conditions between 2012 and 2021 to provide more context.

In response to comments requesting additional examples of extreme weather events and associated impacts to the grid, the Department has added new references to Section V to discuss events such as extreme heat events in California and the Northwest, the 2014 polar vortex impacts to the Midwest and northeastern U.S., and the 2018 “bomb cyclone” cold weather event, among other events. Nearly 20 different industry and consultant reports were added to the final Study to capture the impacts of extreme weather.

In response to suggestions to provide more state-level data, the Department has incorporated various studies focusing on transmission needs at the state level throughout Section V. Xcel Energy, for example, suggested discussing benefits of interconnecting Texas and the Mountain regions. The Department notes that while benefits of increased interconnection with neighboring regions are discussed elsewhere in Section V, none of the studies included under Section VI’s capacity expansion modeling analysis considered new future connections between Texas and the Mountain or Southwest regions.

The Department agrees that alleviating all transmission congestion—and, related, all generation curtailment—is economically inefficient and the Study does not suggest this

strategy should be undertaken. This caveat is appropriately noted in *Section V.b. Regional Congestion and Constraints*: "New deployment of transmission, along with storage and other alternative transmission solutions, can alleviate congestion. If a transmission facility is being considered for the sole purpose of alleviating congestion, the cost of the project would need to be less than the congestion costs that are alleviated for the project to be financially viable," (page 64). Similarly, the Department agrees that there are many causes for long interconnection queues aside from an inadequate access to transmission. This point is appropriately caveated in *Section IV.d. Interconnection Queues* in the passage that begins: "There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase…" (page 48).

## 2.4. Methodology and Modeling

Approximately 32 commenters provide insights related to the Need Study's methodology and modeling.

### Modeling Methodology and Analysis

Many commenters shared their opinions and suggestions on DOE's modeling methodology and analysis in the Study.

Both PJM and SERTP Sponsors state that the Study fails to address concerns about resource adequacy, especially the potential for certain regions to shift their resource adequacy responsibilities to neighboring regions through interregional transmission. Econwerks suggests that DOE conduct a thorough investigation of resource adequacy separate from those conducted by reliability coordinators, RTOs, consultants, and policy influencers who all have an economic interest in grid build-out. Econwerks remarks that DOE should rely on an independent study of transmission needs that is academically rigorous and peer reviewed to ensure scientific accuracy and acceptance by the general public.

Grid United recommends DOE evaluate any need for expanded regional transmission networks to ensure deliverability of resources from large energy zones, which follows the study methodology used by RTOs and utilities when assessing their generator interconnector processes. AEU states that while interregional projects are more challenging to build, DOE should not ignore the significant benefits provided by regional transmission lines, which can face many of the same barriers to construction.

SREA states that given the evolving generation mix, it is important to conduct a more thorough analysis at both regional and interregional levels. SREA states that this is important because not all utilities—like those in Alabama, Florida, and Texas—publish IRPs. SREA acknowledges that while IRPs may be helpful data inputs, they are not the only sources for evaluating future load, retirements, and generation changes. Nevertheless, SREA encourages DOE to collaborate with all utilities to collect IRP data and utility goals to inform future sensitivities and studies in the future.

Xcel Energy suggests that instead of generic solutions, the Study could focus on discussing the benefits of increased connectivity between areas. It indicates that the general nature of the solutions provided does not motivate them to implement the findings of the Study.

Keryn Newman states the Study touts bidirectional power trading between regions, but it overlooks the challenges of interregional merchant transmission, which rely on contracted customers. Newman states that without firm customers, merchant transmission has no revenue stream and is uneconomic to build.

According to NEMA, the largest issue confronting transmission development is less the technical limits of transformers, but rather in the difficulty of obtaining an adequate supply of transformers. NEMA suggests this should be considered as a significant need and included as a study criterion. NEMA adds that the availability of critical products is necessary for the functioning of the grid at the state and local levels, particularly for end-users, and should be considered in transmission planning.

ACC states that it is important to acknowledge that natural gas generation will play a vital role in ensuring a secure, reliable, and evolving lower-emissions grid.

Several commenters discuss the importance of understanding the cost of investments relative to the benefits to the system or to consumers. NJBPU recommends that DOE focus on identifying transmission investments that adequately consider reliability and economic benefits while also facilitating clean energy deployment. NJBPU suggests scenarios should focus on cost-effective solutions that do not rely solely on aggressive policy assumptions. NJBPU believes developing long-distance, high-voltage transmission infrastructure is vital for affordable electricity and reliable clean energy deployment, but consensus requires consideration and quantification of non-clean-energy benefits.

SERTP Sponsors state the Study overlooks transmission costs and siting impacts, which undermines the determination of the true value of transmission needs. Similarly, ERCOT claims the Study does not adequately consider the significant costs associated with the identified transmission additions when analyzing the economic benefit. ERCOT indicates the Study identifies considerable economic benefits for several new transmission facilities across the country, including those connecting Texas to the western U.S. and the Plains region, but fails to address the costs that are likely to be substantial. ERCOT suggests that DOE conduct a more comprehensive cost-benefit analysis so that the net benefit of such transmission facilities can be fully understood. Without such an analysis, the Study does not demonstrate an independent economic need exists to support the construction of expansive and costly new interregional transmission lines. ERCOT suggests that any analysis of improvements should consider the costs associated with constructing all the necessary facilities, rather than focusing solely on a few select projects the Needs Study identifies as having the highest value. ERCOT urges DOE to consider other costs associated with the proposed changes to the power grid, including:

- Additional upgrades to the transmission system to ensure sufficient grid strength and inertia.
- Changes in the costs of managing the dispatch of electricity due to the retirement of older or less efficient power generation caused by increased transfer capability.

- The impact of increased transfer capability on regional dispatch costs due to the intermittent nature of renewable energy sources.
- Adjustments to the requirements for maintaining operating reserves due to increased reliance on intermittent renewable resources.
- Potential modifications to existing market structures and Texas state regulations to effectively handle interregional transfers.

Additionally, ERCOT warns increasing transfer capability between regions can reduce total reserves available to all regions as increased competition from other regions could lead some generators to retire.

ERCOT states that while DOE responds to ERCOT's comment that the Study does not replace the responsibilities of regional entities when it comes to transmission reliability and planning, DOE does not directly address its concern that the Needs Study does not consider costs associated with transmission additions.

Con Edison and AE discuss cost allocation methods. Con Edison emphasizes the importance of fair cost allocation methods that consider the benefits of interregional connections during power system emergencies. AE refers to a recent FERC technical conference that discussed minimum interregional transfer capability. AE notes that experts at the conference raised important concerns like cost allocation, alternatives to transmission infrastructure and assessing the benefits of meeting interregional transfer requirements relative to the investment costs. AE also suggests cost allocation projects should be based on a beneficiary pays approach wherein the beneficiaries of improving the ability to transfer energy will need to be identified and considered as this topic evolves.

National Grid recommends DOE incorporate more detailed regional cost modeling, which would better quantify the operational cost benefits of an interregional connection between New York and New England and provide more insight into how interregional transmission can reduce price volatility and improve generation dispatch efficiency.

Econwerks claims the Study overlooks the natural monopoly and cost complexities in the electric industry. Econwerks states that using the findings from individual RTO transmission expansion plans that are specific to a particular region to determine transmission needs at the national level is not an optimal method of assessing transmission needs.

SERTP Sponsors claim the Study underestimates the transmission needed as the zonal modeling results assessed in the Study do not adequately address impacts on lower voltage systems. It states that proper evaluation of transmission costs is necessary and that economic evaluations that incorporate transmission costs are essential when designating NIETCs. It also states that collaboration with registered planners and coordinators is crucial to incorporating these evaluations into the Study.

AE notes the Study frequently references MISO's *Renewable Integration Impact Assessment*. AE states the RIIA helps identify system issues that could arise with increased renewable energy

penetration, but the Study does not show how to address these issues or focus on implementation steps that would likely be taken as more renewables are brought online. According to AE, MISO did not find any milestones of the system becoming inoperable up to the 50% penetration levels studied; however, AE believes there is still much to learn about effectively integrating higher levels of renewable energy. AE suggests the RIIA results indicate the need for further analysis to truly understand the optimal integration of renewable energy resources.

Gallatin Power recommends further research focusing on the WECC Paths to evaluate significant transmission constraints in the western region.

AEP recommends DOE should acknowledge the importance of local transmission planning in alleviating capacity constraints and congestion. AEP notes that there is significant overlap between reliability violations and economic congestion. AE notes that addressing reliability issues through local or regional reliability projects can proactively address economic congestion.

ERCOT values DOE's recognition that Texas has built more transmission infrastructure than have other regions. However, ERCOT disputes the accuracy of DOE's statement that transmission investment and construction from 2016 to 2020 has experienced a "sharp decline" in ERCOT. ERCOT notes it has seen substantial investments between 2013 and 2016 via the Competitive Renewable Energy Zone (CREZ) initiative led by the PUCT. ERCOT provided a figure in its comment illustrating the consistent increase in transmission improvements over the past decade.

DCC proposes adding a new section or subsection to *Section V: Review of Existing Studies: Current and Future Needs*, detailing information about the Study's overall process and methodology, particularly as it relates to the inclusion of source data and reports. DCC sees the benefit from discussing potential issues and limitations when relying on data from past or regional reports. Similarly, PIOs recommends that DOE acknowledges the limitations of studies and reports chosen for inclusion in the literature review portion in the Needs Study for two purposes. First, PIOs recognize the possibility that identified needs may be more urgent than initially suggested in a study or report included in the literature review portion of the Needs Study. Second, they state that absence of transmission needs in less comprehensive studies does not imply the absence of further needs endorsed by DOE. PIOs also recommend DOE clarifies its own criteria for assessing whether a present or future transmission need exists. PIOs state several studies and FERC's recent regional transmission Notice of Proposed Rulemaking have emphasized the importance of evaluating transmission needs under multiple anticipated scenarios, which includes considering factors such as expected changes in generation, shifting demand trends, and extreme weather patterns. Therefore, PIOs state it is crucial to assess all potential benefits of proposed solutions rather than focusing on limited types.

CEBA similarly suggests DOE provide more explanation on why DOE chose to conduct the Study through a review of existing literature. CEBA proposes adding a new section after *Section II: Legislative Language* to thoroughly explain the Study's overall method, including its limitations,

rationale for the literature review, differences from the NTP Study, and the possibility of under-projecting transmission needs.

### Scenarios

Some commenters shared their thoughts and suggestions on the capacity expansion scenarios used in the Study.

CEBA supports the Study's findings and the approach of grouping Capacity Expansion Modeling study results; it recommends, however, that GDO provides further reasoning on the Study's methods. CEBA highlights the importance of considering large energy customer load and growth often overlooked in transmission planning studies to avoid underestimating clean energy demand and load growth.

ACORE recommends that DOE use the High/High scenario in the final Study as the base case to most accurately reflect the drivers of transmission needs, including IIJA and IRA, and the increasing electrification of buildings and transportation. AMP also proposes the Needs Study should use a scenario with high load and high clean energy assumptions (High/High) as its base case, given passage of the IRA and given EPA's proposed ruling for reducing harmful emissions.[40] The WATT Coalition also believes that the High/High scenario should be used to determine future needs due to the passage of IIJA and IRA best represents the High/High scenarios and recommends placing greater emphasis on higher renewable energy growth assumptions.

Martyn Roetter points out that the Study's discussed scenarios, projecting future grid loads of 7,000 terawatt-hours (TWh) to 8,000 TWh by the 2040s, fail to consider the significant demand for clean electricity to produce green hydrogen or carbon dioxide removal systems. The focus of the Study appears to be on the increased grid load driven by the electrification of transportation and buildings.

NJBPU highlights that the Moderate/High scenarios may include policy assumptions that require high levels of clean energy integration. Consequently, the transmission solutions identified using these scenarios may not correspond to transmission investment needed to maintain reliability in a cost-effective manner. NJBPU suggests incorporating scenarios that prioritize "no regrets" transmission solutions, which can reduce costs and support clean energy deployment without compromising reliability.

### Results and Findings

Some commenters disagree with some of the findings of the Study, while others seek additional clarification.

North Carolina Utilities Commission (NCUC) disagrees with the Study's claim that current utility plans in the Southeast fail to meet the needs identified in the Study, explaining that public

[40] U.S. Environmental Protection Agency. 2023. Proposed Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles. Available at https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.

utilities in North Carolina are involved in long-term transmission planning processes, as required by federal regulations and state law. NCUC emphasizes that studies considered in the DOE draft Study are separate from the ongoing work specific to North Carolina's electric system. Therefore, the results may differ from what is happening in North Carolina. NCUC suggests DOE exclude North Carolina from the statement regarding the utilities in the Southeast lacking sufficient plans to meet anticipated 2035 needs or provide more information to explain the basis for the statement.

SERTP Sponsors also disagree with the Study's claims that the Southeast will need a lot more transmission capacity in the future, as it does not have enough evidence to support this assertion. SERTP Sponsors claim that the Southeast already has a strong transmission system and has been investing in it to meet the needs of customers and to accommodate state energy policies. SERTP Sponsors mention that the Southeast has achieved lower electricity costs, high reliability, and successful implementation of state resource decisions. It notes the Study overlooks some unique characteristics of the Southeast, such as existing long-distance transmission lines and the focus on providing physical transmission so that long-term firm commitments can be served with the intent of no congestion or curtailment. It argues DOE's analysis of transmission investment from 2011 to 2020 is limited and does not reflect current increased investment.

AE indicates that the Study lacks sufficient context for transmission investment decisions, stating that the Study does not pay enough attention to optimizing the overall system or discuss how customers will be affected by transmission spending. AE does not think the Study provides practical guidance on expanding the transmission system in a cost-effective manner. AE adds that it is important to understand the policies and business incentives that have led to the current needs. ACP notes that DOE should highlight the gap between the increasing pace of the energy transition and lack of investment and implementation of interregional transmission. ACP suggests mechanisms like siting assistance, loans, and capacity contracts to bridge the gap between the energy transition and the lack of interregional transmission investment.

In response to DOE's finding that 50% or more of an asset's value can be realized in the worst 5% of hours, Xcel Energy suggest further investigation into the reasons behind the 5% of hours that drive these benefits and the likelihood of encountering those system conditions throughout the lifespan of new transmission assets. Xcel Energy questions how the authors of the Study perceive the risk and value of assets. It says addressing these risks will likely involve considering a broader range of options beyond just expanding transmission.

Xcel Energy also comments on the regional results, as summarized below:

- **Mountain.** The Study draws conclusions about the ability to transfer power between Colorado and the rest of the Western Interconnection. However, the Study also suggests that the eastern parts of the Western Interconnection would benefit from better transfer capability with areas further east. Further analysis is needed to compare the value of improving connections eastward or westward in the eastern part of the Western Interconnection. Comparatively simple solutions, such as changing contractual pathways and adopting new approaches to facility ratings, could provide significant

benefits without incurring additional transmission costs. Any transmission development beyond policy-based mitigation would then be a more optimal solution. The potential value of connecting the Southwest region with the Texas region is considered. Xcel wonders if similar benefits would be achieved by improving connections between the mountain and Texas regions, allowing for greater power transfers between the West and southern SPP or ERCOT.

- **Southwest.** The Study results indicate that the transfer capacity between the Southwest and Texas needs to be increased for improved reliability and resilience. Southwestern Public Service, an operating company of Xcel Energy, serves the area between these two regions in the Plains region. Depending on how the transfer capability is increased, there may be unintended consequences in the Plains area that would need to be addressed in project development planning. Considering the recent events impacting the system in this area, it raises the question of whether a transmission solution is the right approach or if additional investment in cold weather protection would be more cost-effective.
- **Plains.** Xcel Energy believes that the Plains/SPP region has been understudied compared with other regions. Most of the recommendations provided are generic, which makes it challenging to rely solely on the Study for a way forward. The Study's conclusion that average prices in the region have been increasing compared with neighboring regions lacks substantial support and could be addressed in various ways, not just through interregional transmission as suggested by the Study. A more detailed analysis of the factors influencing locational marginal price trends would be valuable in determining the appropriate solution for addressing such changes.
- A couple of commenters describe the advantages of co-locating transmission lines on transportation or other utility corridors. FAS supports the Study's suggestion that co-locating new transmission lines with existing rail, highway, or pipeline infrastructure can be a promising solution to bypassing development challenges. FAS states that it involves negotiating with fewer stakeholders and takes advantage of the proximity to areas with renewable energy potential and avoids disturbing undeveloped land. FAS adds that it can reduce the time and effort required for acquiring leases, increase investor confidence, and speed up the deployment of new transmission infrastructure. FAS suggests DOE's RAPID toolkit can be a valuable resource, although it currently lacks information specific to building transmission lines in railroad rights-of-way. Both FAS and Keryn Newman highlight the SOO Green HVDC [high-voltage direct current] Link project[41] as a potential example for rail co-location with HVDC transmission and note the benefits of burying transmission lines alongside highways and railways. FAS suggests that incorporating co-location into regulatory information resources would greatly benefit future transmission developers.
- PIOs state that although it is beneficial to have connectivity between MISO North, SPP, and MISO South, it is also important for the Study to acknowledge the advantages of increasing direct transfers between MISO North (Midwest) and MISO South (Delta). Additionally, PIOs note that while the Study should prioritize interregional projects that

[41] Available at https://soogreen.com/.

are more challenging to implement, it should not overlook regions that have struggled to build transmission infrastructure within their own market boundaries. The difficulties in developing within MISO South and connecting MISO North and MISO South are examples of significant transmission needs that have national importance and should not be disregarded.

- Con Edison emphasizes transmission expansion efforts in New York should not be dampened by the Study's conclusion that New York's planned transmission exceeds DOE's anticipated needs for both scenarios. Con Edison encourages continuous efforts to expand transmission infrastructure, including at the local level.
- ERCOT believes achieving the economic, reliability, and resiliency benefits outlined in the Study for Texas cannot be accomplished by selectively implementing projects that are deemed to provide the highest value. ERCOT suggests that any analysis of improvements should consider the costs associated with constructing all the necessary facilities, rather than focusing solely on a few select projects with the highest value.

### Interregional Capability Analysis

- Several commenters discussed the factors that should be considered in the assessment of interregional investments.
- PJM raises concerns about the lack of clear criteria or metrics in the Needs Study to gauge the level of transfer capability needs. PJM believes that ongoing work at FERC and the EIPC should be considered to develop appropriate metrics and defers to the ongoing Interregional Transfer Capability Proceeding to establish metrics and methodology.
- Dana Siler expresses concern about the Study's lack of emphasis on connecting the central region of the country to PJM. Siler highlights the testimony of PJM's Vice President, Asim Haque,[42] who raised alarm about PJM's ability to provide reliable electricity in the medium term due to new state decarbonization policies. These policies could lead to the retirement of thermal resources and an increase in the share of renewable energy in PJM's resource mix, potentially affecting its reliability. Connecting PJM to the central region could offer a more reliable solution, reducing the need for aging coal plants and avoiding stranded natural gas assets.

ACORE also points out that DOE uses different measures to quantify interregional ("the amount of power that new or upgraded lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries") versus regional (GW-mi or TW-mi) transmission needs and plans and suggest that DOE elaborate on the relationship between its interregional and regional analyses.

EEI states that determining interregional transfer capacity involves complex and technical analysis and that conversations across industry continue to evolve. According to EEI, the Study

[42] Available at https://ohiochannel.org/video/ohio-senate-energy-and-public-utilities-committee-2-28-2023 and https://search-prod.lis.state.oh.us/cm_pub_api/api/unwrap/chamber/135th_ga/ready_for_publication/committee_docs/cmte_s_energy_pu_1/submissions/cmte_s_energy_pu_1_2023-02-28-1000_137/asimhaquepjm.pdf.

does not appear to consider important factors highlighted at FERC's workshop on interregional transfer capability, including:

- The need for a clear definition of transfer capability.
- Other factors beyond direct connection that can affect the transfers, as determining transfer capability between regions is not as simple as adding up the capacities of power lines between them.
- Any facility planned to facilitate interregional transfers must have clarity and consensus on benefits to ensure appropriate cost allocation and enable the construction through state regulatory processes.
- Significant levels of new transfer capability between regions would likely require upgrading the existing transmission system in the receiving region.

AMPUA and IEDA highlight the limited import and export capabilities of the Southwest region and urge DOE to emphasize the importance of increasing transfer capacity between ERCOT and the Eastern and Western Interconnections.

NJBPU recommends the Study focus on identifying transmission projects that can deliver net benefits from a reliability and economic perspective that also facilitate the energy transition and where they should be constructed. NJBPU adds that when combined with detailed data on candidate transmission projects from the upcoming NTP Study, this could demonstrate the wide-ranging benefits of investing in major infrastructure projects to all stakeholders and help build consensus on the need to develop and fund significant regional and interregional transmission infrastructure.

National Grid emphasizes the significance of interregional transmission in facilitating clean energy growth and economic security, particularly in regions like the Northeast. National Grid believes that valuable insights can be shared with other regions through the Study. In addition, National Grid explains that it can assist DOE in expanding the Study analysis by including operational and resource modeling across regions and evaluating interface impacts on resilience and reliability.

SREA discusses the impact of four major winter events in the past 11 years—the 2014 Polar Vortex, 2018 Cold Weather Bulk Electric System Event, 2021 Winter Storm Uri, and 2022 Winter Storm Elliott—to show that interregional transfer capability between the Southeast and MISO regions is necessary and would provide value.

SPIGs say Winter Storm Elliott revealed serious transmission network problems in the Southeast, which should be considered in identifying the region's interregional transmission needs. SPIGs add the storm revealed that while the Southeast experienced blackouts, the central region had excess wind energy that could not be used due to inadequate infrastructure. SPIGs suggest DOE stress the urgency to prevent future disasters and improve the Southeast's interregional transmission.

Hydro-Québec recommends that DOE provide additional information on the importance of international transmission investments in enabling two-way trade of electricity. It states that by facilitating greater two-way trading of electricity between Québec and the United States, the

benefits of each region can be shared more broadly, promoting renewable development and ensuring a stable supply of clean energy. Hydro-Québec cites studies showing that bidirectional transmission between Québec and the Northeast is crucial for achieving ambitious state climate policies and reducing power system costs. It adds that expanding the clean energy partnership between the Northeast and Québec will require additional HVDC lines, providing numerous additional benefits to the system.

### Department Response

In response to comments related to resource adequacy, the Department added eight industry studies that discuss resource adequacy to *Section V.a. Reliability and Resilience* (pages 59–62) of the final Study. The Department is clear that resource adequacy requirements can be met through a mix of solutions, including, but not limited to, interregional transmission: "Regions meet their resource adequacy requirements through a mix of regional generation, demand response, and firm capacity transfers across intra- and interregional transmission lines" (page 59).

Cost allocation methodologies or analysis are considered out of scope for this assessment of physical need of the transmission system. Supply chain concerns, though capable of having a major impact on the development of new transmission capacity, are also deemed out of scope.

Historic non-incumbent developer transmission investments are discussed on pages 25–27 of *Section IV.a. Historic Transmission Investments*, including the addition of Figures IV-4 and IV-5, which show a comparison of developer investments at the regional and voltage class level.

The final Study highlights that a diverse generation mix is necessary to reliably meet the evolving needs of the power sector, as is stated on page vi of the Executive Summary of the final Study: "Study findings also indicate that interregional and cross-interconnection transmission investments will improve system resilience and alleviate resource adequacy concerns by enabling increased access to diverse generation resources across different climatic zones." Furthermore, many different technologies are considered "clean" for the purposes of grouping scenarios in *Section VI. Anticipated Future Need Assessment through Capacity Expansion Modeling*: "The annual percentage of clean energy generation, including all solar energy technologies (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based and offshore wind power, hydropower, nuclear energy, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration technologies, and landfill gas plants were considered" (page 116). See Department Response in Section 4.4 of this comment synthesis for a discussion of how increased demand due to hydrogen production and carbon dioxide removal is considered in Section VI.

Several commenters requested more insight into how the Department determined criteria for identifying transmission needs. As part of the Department's approach to summarizing transmission needs discussed in the Study, the Department created finding summary graphics in the Executive Summary (Figure ES-7, page xi), Section IV (Figure IV-18, page 50), Section V (Figure V-17, page 109), and Section VI (Figure VI-12, page 142). The Supplemental Material

provides a detailed discussion of the methodology used to categorize information included in the Study as a transmission need.

The MISO *Renewable Integration Impact Assessment* is one of many studies included in Section V, notably pages 54–55 of *Section V.a. Reliability and Resilience*, which discuss the complexities of connecting large penetrations of variable energy resources to the larger transmission system. Findings from this study are appropriately incorporated into the Study.

Commenters also requested more nuanced discussion of the role of local transmission planning for alleviating capacity constraints and congestion. The Department has provided more context in *Section I.a. How to Use This Study* to identify how Study findings can inform existing transmission planning processes. Additionally, see the Department Response in Section 1.6 of this comment synthesis for a response to how interregional transmission investments can have impacts on the local and regional systems.

The Department appreciates ERCOT sharing their data on transmission investments by in-service year. The Department believes the trends of investment shared by ERCOT match that published in the final Needs Study. The Department added information on the CREZ investments and how those impacted the regional investment trends in the final Study in *Section IV.a. Historical Transmission Investments* by adding Figure IV-7 and subsequent discussion (pages 29–31).

In response to commenters requesting an increased focus on high load growth, see Sections 2.1 and 2.3 of this comment synthesis above in which the Department includes additional context regarding the relevance of the high load and high clean energy capacity expansion scenario group in the final Study.

In response to entities who commented that regional need in the Southeast has not been appropriately attributed, the Department has added several references and context to additional studies relevant to the region in Section V of the final Study (pages 58, 62, 69, 78, 79 and 80 in particular). These include both utility studies (e.g., Duke Energy and TVA) and state utility commission regulations. Additionally, the Department made a note in the final Study that acknowledges that the Southeast made large transmission investments prior to the years considered in *Section IV.a. Historical Transmission Investments* (page 21).

With respect to comments that the Plains and Mid-Atlantic regions were underrepresented in the draft Study, the Department added approximately four additional studies and additional discussion on transmission needs in the Plains throughout the final Study (pages 39–40, 59–60, and 80 in particular). Please see the Department Response in Section 2.3 of this comment synthesis above discussing the incorporation of additional references and context in the Mid-Atlantic region.

Several commenters suggested additional discussion of the advantages of co-locating transmission lines in transportation or other utility corridors. In response, the Department has added brand new analysis in *Section V.e. Siting and Land Use Considerations* to discuss the possibility of co-locating transmission in interstate corridors (pages 96–103). This subsection includes recent NREL analysis and a discussion about the feasibility of siting undergrounded transmission lines along highways given a variety of unique characteristics. The data sources

and methodology used to conduct this analysis is included in pages 26–33 of the accompanying Supplemental Material.

In response to comments requesting more discussion of transfer limitations between MISO North (Midwest) and MISO South (Delta), the Department refers the reader to the Department Response in Section 1.6 of this comment synthesis above, which discusses new references added to Section V.a. that further discuss the Regional Directional Transfer Limit between the Midwest and Delta regions and associated transmission limitations.

The units for transmission deployment (TW-mi) and transfer capacity (GW) in Section VI are the commonly used units by capacity expansion models. While these differ from one another and from industry-standard units, the Department continues to use them as they were the units used in the underlying studies. The Department does discuss the use of these units and offers examples of how they can be compared with industry units in *Section VI.c. Within-Region Transmission Deployment* (pages 121–122).

Certain commenters encouraged the Department to consider the current planning assessments and clarify how these plans align with the analyzed scenarios. In response, the Department added *Section VI.e. Comparison with Utility Plans* (pages 139–141) to discuss further how current utility plans for additional transmission development compare with anticipated future need revealed in the capacity expansion models considered in the Study. Table VI-5 (page 140) lists seven industry references, in addition to two industry references included in the draft Study, which were added to the final Study to make this comparison.

In response to commenters highlighting how recent extreme weather events have shown a need for additional interregional transfer capacity, the Department has made several changes to the final Study to incorporate this need. See pages 39–42 of *Section IV.b. Market Price Differentials* and pages 58–59 of *Section V.a. Reliability and Resilience* in particular. Additionally, see the Department Response in Section 2.2 of this comment synthesis above for a discussion of references added related to extreme events.

In response to commenters who believe not enough transmission need is identified in the northeastern regions (New York and New England), including international transfers, the Department made numerous changes to the final Study. The Department acknowledges that the moderate load and high load growth scenarios highlighted in the draft Study did not fully capture the high load growth policies established in these and other regions. For this reason, the Department has additionally highlighted the high growth capacity expansion scenario results throughout the report. See the above discussion on where these changes were made.

Specific to findings of low international transfers, the Department has moved the findings of international transfer capacity from the draft Study to the Supplemental Material. Upon internal review and additional discussions with commenters, the Department believes that the scenarios that fed these results were low in number and did not adequately capture future power system changes. A discussion of the results can be found in the final Study on pages 74–77, 89, 130–131. The Department also supplemented the discussion about international transfers with Canada in *Section V.c. Generation and Demand Changes* on pages 76–80 referencing three other studies.

The Needs Study is an assessment of previously published work and does not include any new modeling. This synopsis incorporates demand forecasts into new capacity expansion modeling, cost-benefit analyses of individual or portfolios of projects, assessments of value of individual or portfolios of projects, and new scenario development for capacity expansion modeling. While many of the analyses requested by commenters are important to transmission system planning, all comments suggesting new modeling methods are considered out of scope. As pointed out by several commenters, some of these requested modeling exercises are being performed in separate Department studies, such as the NTP Study. The Department did add *Section I.a. How to Use This Needs Study* (pages 2–4), which briefly discusses how the findings of the final Study can be incorporated into other planning processes.

While additional project cost analyses are out of scope, the Department does report system costs for several national capacity expansion modeling studies throughout Section V, most notably in Figure V-6 (page 75). Additionally, all transmission expansion results presented in *Section VI. Anticipated Future Need Assessment through Capacity Expansion Modeling* are the result of least-cost optimization modeling, meaning that these transmission solutions were found to be cost-optimal when compared with a suite of other supply- and demand-side solutions under a set of modeling assumptions. While not as resolved as a financial cost-benefit analysis of individual or portfolios of specific projects, least-cost optimization does provide a general sense of the amount of transmission expansion that would be economically viable given a particular set of scenarios.

## 2.5. Other Gaps

Approximately seven commenters provide additional comments highlighting gaps in the Study that DOE should consider.

National Grid, the Blue Lake Rancheria Tribe, ACC, and SPIGs offer insights and challenges specific to their regions or sectors:

- National Grid emphasizes the importance of interregional transmission in the Northeast, particularly during winters, highlighting gas supply constraints and price increases due to reliance on imported liquid natural gas. National Grid also anticipates both Upstate New York and New England to interconnect large amounts of renewable energy in the next decade.
- In reference to Section V.c.2., the Blue Lake Rancheria Tribe notes that while many Tribal nations are actively seeking to build electrical infrastructure, inadequate transmission capacity is slowing adoption of electrified transportation, building electrification, and development of DERs in Tribal lands. The tribe highlights the negative impact of transmission limitations on Tribal nations' economies, leading to a reliance on high-emission fossil fuel generators.
- ACC stresses the need for lower-emissions energy sources in energy-intensive manufacturing sectors like the U.S. chemical industry. It states the importance coordination between DOE, FERC, and states in building national transmission aligned with the most ambitious scenario for transmission investment, urging policymakers at all levels to understand the requirements to meet ambitious projections.

- A lack of transparent market pricing and regional transmission planning leads SPIGs to urge DOE to consider existing needs in the Southeast that may be incapable of quantification, such as those found in utility statements or official regulatory processes. They cite TVA as an example as TVA chose gas power over solar and storage options because of the perceived high expense of transmission costs, despite experts highlighting the benefits of renewable sources for reliability and resilience.

NYTOs suggest DOE incorporate the latest transmission projects that have been included in NYISO's transmission planning to avoid significant omissions that would change the draft Study's conclusions:

- The AC Transmission Project
- The Smart Path Connect Project
- The Tier 4 HVDC Projects (CHPE and Clean Path New York [CPNY])
- The Long Island Offshore Wind Export Public Policy Transmission Need (PPTN) Projects

NYTOs argue that DOE should consider the significant impact of the Long Island PPTN project. If timing poses challenges, they recommend incorporating it in future assessments that could lead to the designation of NIETCs. NYTOs highlight that these transmission projects would effectively address concerns raised in the Study, such as price disparities between upstate New York and Long Island and historical high prices observed on Long Island.

National Grid further points out that national leaders could gain valuable insights from New York's experiences and lessons learned in policy and process development, particularly in the integration of renewable energy. National Grid mentions the 2020 Accelerated Renewable Energy Growth and Community Benefit Act, which has already attracted over $5 billion in investments for local transmission infrastructure to support renewable energy delivery throughout the state. National Grid also discusses major bulk transmission projects, such as Smart Path Connect, CHPE, and CPNY, as well as New York utilities' Coordinated Grid Planning Process aimed at achieving the state's clean energy goals. Lastly, National Grid mentions the PPTN process, which seeks competitive transmission solutions to accommodate renewable energy generation.

### Department Response

The Department thanks commenters for their comments regarding other gaps.

The Department has included a discussion about natural gas constraints during winter months in the Northeast on page 87 of the final Study. See the Department Response to Sections 2.2 of this comment synthesis above for resolution on including Tribal energy needs into the final Study. See the Department Response to Sections 2.3 and 2.4 above for a discussion on capturing high load growth scenarios in alignment with regional policies and high-demand industries. Additionally, see the Department Response to Section 2.4 above for a discussion on references added that address southeastern transmission need.

The Department emphasizes that the Needs Study is not meant to identify particular solutions in *Section I. Introduction*. As such, the Department made a general practice of not identifying

specific transmission projects in the final Study, and therefore projects referenced by commenters are not included in the final Study.

# 3. Transmission Planning and Security

## 3.1. Planning and Coordination

Approximately 28 commenters mention topics related to transmission planning and coordination.

Several commenters strongly agree with DOE's conclusions in the Needs Study that there is a need to expand interregional and cross-interconnection transmission planning to improve reliability, support electrification efforts, support the clean energy transition, and reduce customer costs. ACORE indicates that the Study could identify transmission planning processes as a transmission need, thereby expanding the Study scope to determine what gaps and opportunities could improve regional and interregional transmission planning processes.

Several commenters remark on the failure of current regional and interregional transmission planning processes and stress the importance of improving them. For example, AEU and PIOs argue that current transmission planning processes across the country result in "inefficient investments that foreclose meaningful competition, miss out on economies of scale, and result in consumers paying considerably more for significantly less—less choice, less capacity, less flexibility, less resiliency, and ultimately less reliability." AEU, AEP, PSEG, and PIOs advocate for the use of multi-value and scenario-based approaches to planning, which enhance the processes' ability to determine more cost-effective investments (providing energy price benefits to consumers), address uncertainties, and reduce system-wide costs and risks. Similarly, National Grid recognizes that future investments need to take into consideration a holistic view of the diverse needs of customers and system at large such as reducing transmission curtailments, bolstering grid resiliency, enabling a clean fuel mix, and access to low-cost resources. AEU notes that eliminating existing barriers to regional and interregional transmission projects can maximize net consumer benefits across regions and improve reliability and resilience in the face of increasing extreme weather events. PJM requests that DOE assess how resilience considerations in intermediate- and long-term regional planning processes affect the determination of transmission needs and corridor designation.

Similarly, AE notes that transmission planning processes need to be more dynamic and flexible to respond to evolving needs and solutions. AE notes the need for transparent, robust planning processes with meaningful stakeholder engagement and consideration, wherein projects with long lead times are reviewed every 3 years to ensure that initial project planning assumptions remain accurate. AE and other commenters indicate that transmission planning processes must modernize to ensure that diverse solutions and advancements are properly considered.

While AE expresses its appreciation for DOE acknowledging that the intention of the Needs Study is not to replace current planning processes performed by regional planning entities, it believes that the Study could benefit from identifying current reforms across regulatory levels that might address needs identified in the Study. For example, several commenters, including AE, NJBPU, ITC, and ACORE reference MISO's LRTP, a planning effort consisting of multiple

tranches of projects focused on various areas and needs of the MISO footprint. AE also references the MISO and SPP JTIQ Study, which is helping to address the need for increased transfer limits between the Midwest and Plains regions. ITC urges DOE to be attentive of the benefits of incumbent utilities being allowed a right of first refusal (ROFR), as witnessed in the successful approval of the LRTP Tranche 1 portfolio and ongoing development of Tranche 2.

AEP describes its interregional planning, minimum transfer proposal in detail, and suggests an Interregional Reliability Planning Assessment (IRPA) be conducted to determine the appropriate minimum interregional transfer capability necessary for regions to cost-effectively support reliable system operation.

SPIGs illustrate the pressing transmission needs in the Southeast, despite limited data on the region, and suggests that DOE consider them in the Needs Study. SPIGs detail that throughout the Southeast, utilities do not proactively plan for necessary transmission expansion. SPIGs emphasize that the Southeast's dire need for transparent market pricing and regional transmission planning require creative solutions to expose regional needs. For instance, SPIGs explain that SERTP Sponsors' regional transmission plan has not once included a regional transmission facility, primarily due to its narrow regional evaluation process. SPIGs explain that local plans, which lay the groundwork for the regional plan, typically only consider reliability needs, and rarely conduct multi-value planning, which limits the benefits that inform the analysis. And when a regional project is considered, SPIGs describe how, as expected, larger regional project costs are far greater than small local project costs, resulting in none of the regional projects being selected. Given all these challenges, SPIGs argue that the prospects for transmission development in the Southeast are "slim under the current planning paradigm," and therefore Southeast planning processes will provide minimal assistance in DOE's effort to identify transmission needs.

Other recommendations by commenters include AEP suggesting that DOE recognize that local transmission planning is important in alleviating capacity constraints and congestion and in securing a reliable and resilient transmission system. DCC recommends that DOE add a section on best practices for integrating its findings into regulatory proceedings or planning processes.

Lastly, NEMA advocates strongly for siting authorities on the federal, state, and local levels to encourage the use of existing rights-of-ways along railroads, highways, brownfields, and other corridors for transmission development.

### Barriers to Transmission Planning and Development

Several commenters also discuss barriers to transmission planning and development. AEU and others agree with the many challenges to siting high-voltage lines summarized in the Needs Study. Commenters elaborate that challenges to planned interregional transmission include aligning stakeholders across regions with divergent priorities, processes, and benefit analyses; arranged planning processes that lead to prioritizing local; cost allocation; and siting and permitting hurdles. Furthermore, AEU observes that barriers to interregional planning make it challenging to optimize net consumer benefits and create investment gaps near and across market seams because regional planning authorities largely focus on local and regional investments and generator interconnection requests. AEU elaborates that the lack of dedicated

siting authorities, staff, expertise, and funding, as well as a wealth of "'veto points' where any single siting process can result in a project's rejection," all provide major barriers to transmission approval. The Utah Public Lands Coordinating Office sees the biggest hurdle impeding national transmission needs as National Environmental Policy Act (NEPA), given its expansive and lengthy environmental reviews.

As mentioned above, ITC argues that the most pressing issue hindering transmission development is uncertainty driven by the removal of the federal ROFR. ITC goes on to reference recent research supporting the benefits of FERC's ROFR. PSEG agrees, stating that the elimination of ROFR is one reason for the decline in transmission investment across the country.

Hydro-Québec also suggests that DOE should identify that new market mechanisms and commercial models are needed for efficient transmission development, as financing "will require adaptable funding mechanisms which reflect more dynamic performance of the resource."

PSEG also highlights the planning barriers that exist in multi-state RTOs with varied state public policies and discusses the significant challenges to transmission planning in specific regions, noting that current PJM/NYISO transmission planning and allocation rules largely limit options available for transmission projects that would strengthen ties between the two regions. For example, PSEG emphasizes that within PJM, there are 13 states with varying state public policies. PSEG elaborates that large RTOs also struggle to properly generate a load forecast that captures anticipated load and future demand across states, as trends evolve rapidly, leading to understated load forecasts. SPIGs detail the specific challenges faced in the Southeast's transmission planning processes, stating that the regional planning processes themselves are a barrier to regional and interregional transmission development. Rather than approach transmission planning top-down, like independent planners in RTO/ISO regions, SPIGs note that the region's transmission planning is carried out by the transmission-owning utilities themselves, whose own financial incentives favor local, rather than regional or interregional investment.

AE discusses considerations around the minimum interregional transfer capability requirement that was the subject of a recent FERC technical conference.[43]

Xcel Energy suggests that DOE include additional discussion on how to utilize existing cost allocation mechanisms, while identifying gaps in those mechanisms to confirm that the costs required to address the Study's identified needs are "just and reasonable."

### Interconnection

Several comments relate to the interconnection process and interconnection queues.

[43] Federal Energy Regulatory Commission. 2022. Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements held December 5–6, 2022, Docket No. AD23-3-000. Available at https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

Many commenters note their support for DOE in identifying growing interconnection queue delays as being linked to transmission needs. For example, AES appreciates that DOE includes a section on interconnection queues and describes the relationship between queue delays and the transmission needs. AE asserts that from its experience, interconnection process delays are largely due to affected system issues and projects that drop out of the queue and create the need for re-studies. AE believes that DOE should identify reforms that address specific issues in various regions. AES mentions that DLR could help alleviate interconnection queue delay if transmission planning models incorporate DLR data and insights.

Xcel and Keryn Newman comment on DOE's discussion of generation interconnection queues as a potential indicator of transmission need. Newman states that the Study relies too much on the number of generation projects in interconnection queues as an indicator of transmission need and fails to consider that only a small fraction of projects in the queue is realized. Xcel Energy asserts that queue levels are more dependent on near-term activity, like IRPs and the release of environmental goals, and less aligned with long-term resources shifts.

Econwerks references recent Lawrence Berkeley National Laboratory work estimating that only 14% to 21% of what is in the queue will get built.[44] Econwerks explains that "this is not surprising…when for instance in the MISO footprint the amount of generation in the current queue (1400+ projects totaling 244 GW) far exceeds MISO's 2011 all-time system summer peak demand of 127GW,"[45] which if all installed, "…would take an electrification of transportation even more aggressive than that contained in the draft assessment, a supernormal new inter-RTO dependency, or…an impossible to attain number of new resources. " Econwerks argues that just because policy subsidies encourage developers to undertake the development of generation projects, not all that enter the interconnection queue should be constructed.

ACP claims that the needs identified in the Study will not be realized by relying on generators' willingness to pay for large-scale upgrades. ACP notes that in many regions, regional power networks are being planned and expanded on a piecemeal basis through the project-by-project interconnection process, which leads to inefficient outcomes that ultimately cost consumers. AEG notes that few projects successfully result from the interconnection process, as significant time is required for interconnection review, resulting in many projects ultimately withdrawing applications.

### FERC Order 1000

Some commenters mention FERC Order 1000 and its inefficiency in encouraging interregional transmission planning. AEU and PIOs point out that since the Order was issued in 2011, no new

[44] Wiser R. LinkedIn blog (April 7, 2023). Available at https://www.linkedin.com/posts/ryanwiser_much-of-the-proposed-capacity-in-the-us-interconnection-activity-7049812522169761792-bT9K?utm_source=share&utm_medium=member_desktop. Posting references: Lawrence Berkley National Laboratory. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Available at https://emp.lbl.gov/queues.

[45] Midcontinent Independent System Operator. 2023. Generation Interconnection Queue: Overview. Available at https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/.

major interregional transmission projects have been approved and built[46] and the pace of high-voltage transmission expansion has slowed substantially. AEU elaborates that because local reliability projects are excluded from regional planning processes under Order 1000, the result is a piecemeal approach that has failed to bring about regional transmission build-out, resulted in backlogged interconnection queues, and yielded increased congestion and constraints. PSEG states that Order 1000 works directly counter to the robust, multi-value transmission planning needed, and references an August 2022 study by Concentric Energy Advisors that supports their argument.

PIOs state that the interregional coordination process under Order No. 1000 is effectively broken and point out that loopholes in the Order have resulted in most projects approved in RTO regions to be left out of the competitive process for rulemaking. Monitoring Analytics also argues that even with the implementation of FERC Order No. 1000, there is still no "transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a clearly defined and enforceable total project cost cap, or to require that transmission owners obtain least-cost financing through the capital markets."

Furthermore, Monitoring Analytics suggests that PJM's Regional Transmission Expansion Plan (RTEP) rules for competitive transmission expansion be built upon FERC Order No. 1000 to ensure real competition between incumbent transmission providers and nonincumbent transmission providers, improve transparency (specifically addressing issues related to data access and cost impacts), and strengthen the queue management process for nonincumbent transmission investment.

### Transmission Coordination

National Grid, Con Edison, NEMA, PSEG, and PIOs agree that there are significant benefits of interregional coordination. PSEG adds that interregional coordination helps ensure grid resilience. Additionally, PIOs recall that researchers Patrick R. Brown and Audun Botterud, from the Massachusetts Institute of Technology, found that "'inter-state coordination and transmission expansion [including across regions and interconnections] reduce the system cost of electricity in a 100% renewable U.S. power system by 46% compared with a state-by-state approach, from 135 $/MWh to 73 $/MWh.'"[47]

PSEG encourages improved coordination and collaboration between RTOs and member companies because member companies may be better equipped to capture trends that would lead to more accurate regional transmission planning. NEMA also encourages DOE to specify paths for improved cooperation among regional grid interconnections, in addition to any permitting or other institutional reforms essential for national transmission development.

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[46] The Brattle Group, Inc. 2021. A Roadmap to Improved Interregional Transmission Planning, p. 3. Available at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[47] Brown P, Botterud A. 2021. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System, p. 115. Available at https://www.sciencedirect.com/science/article/pii/S2542435120305572.

Other comments suggest that DOE itself coordinate with planning and other entities to better understand regional needs. The NYTOs suggest DOE coordinate with NYISO, PJM, and ISO-NE on further studies projecting the need between New York and the Mid-Atlantic and New England regions before considering any NIETC designation. SERTP Sponsors urge DOE to coordinate with NERC-registered planning coordinators and transmission planners (particularly EIPC). Con Edison suggests that DOE encourage NYISO to work with ISO-NE and PJM to examine the needed interregional transfer requirements.

NEMA believes that increased collaboration and leadership among federal agencies can enable highway rights-of-way to be utilized more quickly, stating that DOE, FERC, the Federal Highway Administration (FHWA), the Department of Interior, and others are key in the development of transmission in rights-of-way.

The Utah Public Lands Coordinating Office notes that building out the transmission required to support growing generation capacity will necessitate coordination with state and local governments. The Office explains that most lines in the western United States are sited on public lands administered by the Bureau of Land Management and the U.S. Forest Service (USFS), and relationships are frequently stretched and tested when direction, policies, and procedures passed down from the federal government change every few years. The Utah Public Lands Coordinating Office elaborates that insufficient coordination between the federal government and state and local governments is a major issue resulting in distrust between governments and energy companies. As a result, Utah requests frequent communication in order to expedite national goals to expand transmission infrastructure and support the anticipated increase in energy production.

### Alignment with FERC

A few commenters, including DCC, CEBA, and EEI, want to ensure that DOE's efforts are coordinated with FERC reforms, including those intended to improve transmission planning and generator interconnection processes.[48] DCC believes it is imperative DOE align its activities with FERC's transmission planning, cost allocation, and generator interconnection initiatives. CEBA notes that GDO should ensure NIETC designation activities are complementary to FERC reforms on transmission planning and FERC backstop siting so that transmission planning and siting processes are coordinated and do not delay transmission development further.[49] EEI also remarks that DOE cannot overlook ongoing transmission planning reforms. EEI calls out one statement in the draft Study, that "many existing transmission planning processes 'are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons,'" claiming that the statement is overly broad and fails to acknowledge FERC's recent proposed reforms to existing transmission planning policy, such as the Notice of

[48] Utility Dive. 2023. FERC works 'feverishly' on transmission reform, with near-term focus on interconnection rule. Available at https://www.utilitydive.com/news/ferc-transmission-planning-generator-interconnection-reform/645267/.

[49] Federal Energy Regulatory Commission. 2022. Applications for Permits to Site Interstate Electric Transmission Facilities, Notice of Proposed Rulemaking, 181 FERC 61,205. Available at https://www.ferc.gov/media/e-1-rm22-7-000.

Proposed Rulemaking to change existing regional transmission planning and cost allocation requirements.[50]

### Department Response

In response to comments requesting an analysis of how past regulations may have impacted historic transmission investments, the Department added a brief description of federal policies and regulations in *Section IV.a. Historic Transmission Investments* on these topics to the final Study (pages 28–29). The Department does not draw any conclusions about the effectiveness of these policies and regulations, however.

The Department received several comments requesting additional information regarding the shortcomings of existing transmission planning processes. The Department reiterates that the Needs Study is not meant to displace existing transmission planning processes nor the reliability standards they address. Rather, the Department believes it will be an important addition to overall industry and government planning efforts to reduce transmission congestion and capacity constraints that adversely affect consumers. Consequently, the Department has determined an analysis of existing planning processes is beyond the scope of this Study. However, as noted in the Department Response to Section 1.4 above and in response to commenters requesting a "best practices" section for integrating these Study findings in regulatory proceedings or planning processes, the Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the introduction to discuss how entities may use the findings contained in this Study to inform multi-value and scenario-based planning.

Relatedly, several commenters encouraged the Department to discuss pathways for improved coordination and collaboration between regional planners and between states and local governments and federal agencies. In response, the Department provides recommendations for how transmission planning entities might use the findings of the Study to guide coordinated transmission planning and development efforts across systems and regions. *I.a. How to Use This Needs Study* (pages 2–4) also provides recommendations for how states and local governments might incorporate Study findings in their own regulatory and planning processes to guide coordination with other states, regional transmission planning authorities and federal agencies. The Department additionally notes that the Brown and Botterud study referenced by commenters is discussed at length in the final Study.

Additionally, commenters suggested the Department identify current planning efforts and reforms that might address needs identified in the Study. In response, the Department highlights transmission planning processes, such as the MISO Multi-Value Project Portfolio and Long-Term Regional Transmission Plan, which have resulted in transmission project portfolios capable of addressing multiple need drivers (page 31). The Department does not, however, hypothesize how reforms to various state or federal regulations—including those of FERC—could impact future investments.

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[50] Federal Energy Regulatory Commission. 2022. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000, 179 FERC 61,028. Available at https://www.ferc.gov/media/rm21-17-000.

The Department agrees that there are many causes for long interconnection queues aside from inadequate access to transmission. This point is appropriately caveated in *Section IV.d. Interconnection Queues* in the passage that begins "There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase…" (page 48). Certain commenters encourage DOE to consider the use of existing rights-of-way for transmission siting along railroads, highways, brownfields, and other corridors. In response, and as noted in the Department Response in Section 2.4 above, the Department has added new analysis and extensive discussion to *Section V.e. Siting and Land Use Considerations* of the final Study to discuss the possibility of co-locating transmission along highways (pages 96–103).

In response to several commenter requests to elaborate on challenges to planning transmission, particularly interregional transmission, the Department has significantly expanded and restructured Section V.i. in the draft Study to provide a more in-depth discussion of transmission siting and land use considerations, now incorporated into *Section V.e. Siting and Land Use Considerations* of the final Study (pages 95–108). This section includes several additional references to further the discussion on challenges of siting transmission, co-locating transmission along other energy corridors, balancing competing land use interests, and community, stakeholder and Tribal engagement during siting and permitting of transmission.

Several commenters additionally suggested the Department ensure NIETC designation activities are complementary to FERC backstop siting authority. The Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

## 3.2. Physical and Cybersecurity

A few commenters suggest that DOE expand on its discussion of physical or cybersecurity in the Needs Study. PSEG agrees with the Needs Study's assertion that transmission can provide resiliency in extreme weather events; however, it emphasizes the need for resiliency planning to mitigate physical and cyber security threats and urge DOE to include this need in the Study. PSEG explains that "there are significant interdependencies between [transmission] systems" and any attack, "no matter how small or how isolated, can have a far-reaching impact beyond one substation or even one company." PSEG cites recent FERC initiatives[51] and communications, and PJM's Attachment M-4 process,[52] to indicate that there is a consensus among experts and that the grid's physical and cyber security need to be prioritized. PSEG also cites its efforts to engage in resiliency planning at a state level and includes insights, which were

[51] Federal Energy Regulatory Commission. 2022. Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives, Notice of Proposed Rulemaking, 180 FERC 61,189, Docket No. RM22-19. Available at https://www.ferc.gov/media/e-1-rm22-19-000. (This NOPR supersedes the Commission's December 2020 Cybersecurity Incentives NOPR. Cybersecurity Incentives, Notice of Proposed Rulemaking, 173 FERC 61,240, Docket No. RM21-3.)

[52] PJM Interconnection. Open Access Transmission Tariff, Attachment M-4. Available at https://agreements.pjm.com/oatt/34859.

emphasized in its recent testimony before the Assembly Telecommunications and Utilities Committee of the New Jersey Legislature.[53] These include: (1) PSEG's efforts to the ensure the physical security of the grid and address critical infrastructure needs, (2) the "continued vitality and increasing importance" of public-private collaboration, (3) the need to invest in the future resiliency and reliability of the grid, and (4) supply chain concerns.

Utah Public Lands Coordinating Office states that increasing interregional transmission capacity could increase or decrease system vulnerabilities. The Office urges DOE to prescribe methods to prevent and combat cybersecurity threats in the Needs Study. Econwerks implies that there are benefits to a fragmented national grid, arguing that system failures can be isolated. Econwerks cites the summer 2003 U.S. blackout, in which the Northeast was able to protect itself from the cascading disturbance in MISO, PJM, and Canada. Econwerks urges the Needs Study to consider the reliability implications of a highly connected national grid.

Keryn Newman argues that undergrounding transmission lines along transportation corridors would improve grid security.

#### Department Response

The Department thanks commenters for their comments regarding physical and cybersecurity. Except for physical security of the grid as it relates to grid reliability and resilience, the Department has determined that security issues are outside the scope of the Needs Study. This omission is not meant to imply that the Department does not find issues of grid security of vital importance, however. The Department is working on security issues in other programs, notably within the Office of Cybersecurity, Energy Security and Emergency Response, the Grid Modernization Initiative, and the Office of Electricity.

### 3.3. Environmental

#### Environmental Impacts

Several commenters suggest that DOE emphasize the many environmental concerns around new transmission.

The Center for Biological Diversity emphasizes the need to minimize negative impacts from utility-scale transmission and generation development. It explains that energy projects are disproportionately sited in environmental justice communities, further burdening populations, and too often sited in environmentally sensitive habitats. The Center for Biological Diversity cites directives in the IIJA, which instruct DOE to facilitate transmission expansion in a way that avoids and minimizes impacts on sensitive environmental areas and cultural heritage sites. To fulfill this mandate, the Center for Biological Diversity encourages DOE to restrict transmission development to areas where NWAs are insufficient to meet needs. Additionally, it encourages DOE to prioritize development in previously degraded lands to minimize impacts on communities, habitats, and species and to, under no circumstance, facilitate the connection of new transmission to fossil fuel power generation. The Center for Biological Diversity explains

[53] New Jersey Assembly Telecommunications and Utilities Committee, March 20, 2023.

that the focus should be on a rapid transition away from all fossil fuel resources and suggest that degraded landscapes like Superfund sites, brownfields, landfills, abandoned mine areas, and contaminated or abandoned agricultural lands are more suitable for large-scale renewable energy projects. The Center concludes that additional renewable energy and necessary transmission should be built with appropriate community input on degraded lands or lands with existing rights-of-way like highway or railway corridors, which would streamline the review process and minimize conflicts, delays, and adverse impacts on the environment.

The Center for Biological Diversity also mentions that the construction of new transmission lines in previously undisturbed areas can negatively affect sensitive ecosystems, including critical habitats for threatened and endangered species. Additionally, construction of new lines can increase air, water, and noise pollution and disrupt commercially or culturally important natural vistas. The Center notes that these impacts sometimes fall on communities that are not the beneficiaries of electricity to be delivered via the new line.

Similarly, the Utah Public Lands Coordinating Office states that it is not unusual for transmission lines to be in or near critical habitats for endangered and threatened species. Therefore, the Utah Public Lands Coordinating Office recommends that transmission lines should be placed in existing disturbed corridors wherever feasible. It states that this has posed significant challenges, especially in Sage-grouse Management Areas. The Office also adds that the current Needs Study fails to sufficiently address the collaboration across state borders to support species planning, habitat improvements, and reducing disturbances.

EDF supports DOE's statement in the draft Study that "[e]xpanded transmission along with storage and other non-wire alternatives could create avenues for frontline communities to have access to community-owned renewable generation projects which could decrease costs, reduce air pollutants that cause adverse health impacts, and advance energy democracy."[54]

Econwerks states that the Needs Study fails to mention that transmission development has externalities that affect land use, the natural environment, farming, and tourism.

The Utah Public Lands Coordinating Office notes that the largest hurdle to transmission development will be the lengthy NEPA process, required when potential transmission projects cross state boundaries and traverse diverse terrain like buttes, valleys, canyons, and basins. The Utah Public Lands Coordinating Office states that NEPA requirements have become increasingly complex, which the Office represents as further amplified by the revised National Environmental Policy Act Implementing Regulations, enacted by the Biden Administration on April 20, 2022, which has led to increasingly complex NEPA requirements.

### Extreme Weather Events

Many commenters, including Con Edison, EDF, AMPUA and IEDA, and others comment on DOE's discussion of the need for transmission to bolster system resilience and reliability during extreme weather events. For example, ACP states the importance of interregional transmission

[54] U.S. Department of Energy. 2023. National Transmission Needs Study: Draft for Public Comment, p. 41. Available at https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.

in assisting in recovery from increasingly common extreme weather events. AEP mentions that with the increased intensity of weather events, transmission development is needed to make sure the grid is reliable. National Grid comments that climate change will continue to increase the intensity of weather events and therefore cause more transmission level outages.

Commenters point out how unprepared states are during extreme weather events, and go on to mention causes of grid failures, such as frozen pipelines and wind turbines. Commenters suggest that additional transmission interconnections could reduce impacts during such catastrophic events. PIOs agree with DOE's findings that that weather risks can be mitigated if utilities share generating resources, aid with restoration and recovery, and improve frequency response. SREA also highlights the importance of geographic diversity of generation resources in ensuring reliability and resiliency, and specifically mentions the potential expansion of the Regional Directional Transfer Limits promised to be included in Tranche 4 of MISO's LRTP as vital to future system reliability and resilience. NYTOs state that the development of new transmission will be key to accommodating the transition to clean energy resources, supporting higher demand due to electrification, and reinforcing the grid to withstand extreme weather events.

The Utah Public Lands Coordinating Office comments on the need to enhance reliability and resilience in the Mountain region, primarily due to the increased occurrence of power outages caused by extreme heat and wildfires becoming more common due to climate change. The Utah Public Lands Coordinating Office elaborates on Utah's restoration efforts and the potential for fires to damage energy infrastructure.

Con Edison, AMPUA, and IEDA note that new interregional transmission can connect geographically diverse resources, which can help the transmission system withstand extreme weather events. EDF recommends that DOE recognize that minor weather events also have significant impacts on resources and regions. EDF uses examples of data collected by the National Oceanic and Atmospheric Administration that show project weather trends.

The Blue Lake Rancheria Tribe recommends DOE discusses seismic activity in Humboldt and Del Norte counties, potential grid capacity shortfalls, the need for substation and distribution grid upgrades, and sea level rise when assessing energy system reliability and resilience needs specific to California.

The Blue Lake Rancheria Tribe further asserts that Tribal nations need to upgrade their energy infrastructure (including transmission, substation, and distribution) as many Tribal nation areas are rural, remote, and subject to multiple hazards. Tribal facilities are often the only critical infrastructure in rural and remote areas and climate resilient electrical infrastructure can deliver a wide array of emergency services.

Multiple organizations—including Grid United, SPIGs, SREA, and others—assert that the Study should include more information on Winter Storm Elliott. SREA explains how Winter Storm Elliott, along with other extreme weather events disrupted utility operations. ACORE recommends that DOE integrate the following resource into the analysis: The Value of Transmission During Winter Storm Elliott, Grid Strategies LLC (2023), which evaluates the benefits of how interregional connection would positively impact during the storm.

Newman states that aboveground transmission lines in remote areas only add risk to the system from wildfires, hurricanes, tornadoes, sabotage, and other grid failure events. Newman suggests that a smaller system in which load and generation are closer together decreases risk because there are fewer potential points for failure. Newman argues that modern technologies other than aerial wires should be deployed to minimize burdens, avoid private property conflicts, and reduce opposition to transmission projects.

SERTP Sponsors comment that while the Needs Study addresses its concern that transmission would not mitigate tornado events, the Study still inaccurately indicates that transmission would mitigate hurricane events. SERTP Sponsors argue that the Study should make clear that both tornadoes and hurricanes are extreme weather events with impacts that likely would not be mitigated by increased transmission capacity.

### Department Response

Commenters note the draft Study fails to mention that transmission development has externalities that affect land use, natural ecosystems, farming, and tourism. In response, the Department has included additional references and context to *Section V.e. Siting and Land Use Considerations* to discuss how transmission siting must balance competing land use interests, along with a text box highlighting DOE work on transmission siting (pages 103–106). Additionally, see the Department Response to Section 2.4 above for a discussion on co-locating transmission in energy corridors.

In response to comments recommending transmission be built with appropriate community input on degraded lands or lands with existing rights-of-way, the Department has included, as noted in the Department Response to Sections 1.6 and 3.1 above, an additional subsection in *Section V.e. Siting and Land Use Considerations* to discuss of the importance of community, stakeholder, and Tribal engagement (pages 106–108). The Department also includes a text box discussing the Department's work on energy justice.

Several comments recommend DOE further recognize the role of extreme weather events in identifying transmission needs. The Department has expanded discussion of extreme weather and its impacts on the transmission system in *Section V.a. Reliability and Resilience* (pages 55–59). This expanded section includes numerous additional references suggested by commenters, including references to an extreme heat event in California, the 2014 polar vortex impacts to the Midwest and northeastern United States, and the 2018 "bomb cyclone" cold weather event, among other events. See additional comment resolutions related to extreme weather events in Department Response to Sections 2.2 through 2.4 above.

The Blue Lake Rancheria Tribe outlines several needs for improved energy system reliability and resilience, including seismic activity in Humboldt and Del Norte counties, grid capacity shortfalls, substation and distribution grid upgrades, and sea level rise. In response, the Department has expanded discussion of the risks posed by seismic activity in northeastern California, including impacts in Humboldt County, and sea level rise to *Section V.a. Reliability and Resilience* (page 59). The additional context provided on sea level rise, specifically the transmission system risk from hurricane-related storm surge, addresses SERTP's concern that the risk of hurricanes to the transmission system is not adequately explained in the draft Study.

In response to several commenters recommending the Study include more information on Winter Storm Elliott, the Department expanded discussion of Winter Storm Elliott in Section V.a. and incorporated various references provided by commenters to support additional information.

## 3.4. Other Transmission Issues

Several commenters express other concerns related to transmission, including the risks, limitations of, and alternatives to transmission expansion.

ERCOT argues that increased interregional transmission can increase reliability risk. ERCOT cites the January 2019 Eastern Interconnection event, which "put the entire Eastern Interconnection on the brink of a collapse." Furthermore, it cites resource adequacy concerns and argues that fewer regions will be equipped to support themselves or help neighboring systems during system disturbances if there is greater interdependency between regions. ERCOT urges DOE to address these concerns in the Study. Additionally, ERCOT states that additional transmission facilities would be needed to regulate stability and voltage if ERCOT increased connection to other regions, and notes this could be costly.

Keryn Newman objects to the Needs Study's "impossible goal to eliminate congestion on the grid." Newman argues that new generation, in regions with high prices, would be a more effective solution to solve economic congestion than new transmission lines. Newman objects to the Needs Study's statement that estimates of an additional 1 GW of transmission capacity between Texas and the Southeast would have saved customers $75 million during Texas's 2019 heat have. Newman argues that this estimate does not include the cost of building the transmission line and does not consider whether additional peaking generation in Texas would be a more cost-effective alternative.

The Center for Biological Diversity urges DOE to consider alternative ways to meet energy needs in addition to transmission expansion and argues that to meet mandates defined in the IIJA, Pub. Law 117-58, the Needs Study must address methods to minimize the adverse impact of transmission deployment on environmental and cultural heritage sites.

AEG notes that Sonny Anand, Director, Infrastructure Investments for National Grid, emphasizes the importance of stakeholder engagement in transmission coordination. AEG references Anand's discussion of a successful engagement model, which would benefit, among other things, from consideration of the economic impacts and potential adverse consequences of transmission development, especially when vulnerable communities are involved. AEG also references discussion that asserts that developers need to ensure new rights-of-way are identified, communicated, and adequately analyzed for community impact, share the benefits of new projects with impacted communities, and seek opportunities such as disadvantaged business set asides and training/apprenticeship programs to economically empower impacted communities.

Keryn Newman objects to the Needs Study's statement that "large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through

increased transmission is cost-effective for neighboring regions." Newman argues this approach is only low-cost due to taxpayer-funded subsidies and lower-cost lands and that "turning rural America into an energy serfdom to provide power to far-away cities" benefits urban communities that do not want to build infrastructure in their own backyard. Newman also argues that the statement exhibits "cultural and political elitism." Furthermore, Newman argues that the Study dismisses legitimate landowner concerns as "NIMBYism" and barriers to transmission development without attempting to address them. Accordingly, Newman concludes that the Study lacks awareness and empathy.

Two commenters identify obstacles to transmission investment. Monitoring Analytics emphasizes the need for competitive transmission development. Furthermore, it notes the need for mechanisms that allow transmission planners to compare the costs, risks, and benefits of transmission development versus generation development. Additionally, Monitoring Analytics explains that transmission projects tend to exceed their estimated costs, which should be reflected in any robust cost-benefit analysis.

Avangrid supports DOE's statement that New England's constrained natural gas system poses reliability concerns in the winter when gas demand is high for both heating and electricity. Similarly, National Grid acknowledges the risk of natural gas constraints in New England and adds that these risks are exacerbated by cold winters, electric heating, and dependence on internationally imported fuels. It asserts that interregional transmission capacity can reduce these reliability concerns.

NEMA remarks that large power and distribution transformers are vital components of the grid, and long lead times on delivery could compromise grid operations and prevent power delivery to end-users.

The Blue Lake Rancheria Tribe encourages DOE to consider its reliability and resiliency needs. The tribe details existing capacity constraints, which limit renewable development options, and emphasizes the need to upgrade the single 115 kV line supplying power to its region.

### Department Response

In response to commenter concerns that increased interregional transmission can have local and regional impacts, see Department Response to Section 1.6 of this comment synthesis. In response to commenter concerns about eliminating congestion in an economically efficient way, see the Department Response to Section 2.3. In response to commenter requests for project cost analyses and supply chain issues, see the Department Response to Section 2.4. In response to comments on risks posed by winter gas supply, see the Department Response to Section 2.5.

In response to concerns of Tribal energy needs, environmental degradation, landowner concerns, and stakeholder engagement during siting activities, see the Department Response to Sections 1.6, 2.2, 2.4, 3.1, and 3.3. The Department stresses that addressing landowner concerns is critical to ensuring just and equitable outcomes in transmission deployment. The Needs Study makes no reference to "NIMBYism" and the Department has taken care to ensure that landowner concerns are not presented as a barrier to transmission deployment in the final Study.

In response to commenter concerns about finding alternative means to meet energy needs, the Department did include a lengthy discussion on numerous transmission technologies, which is available in *Section V.d. Alternative Transmission Solutions* (pages 89–95). The Department additionally stresses that "transmission" is meant to be technology neutral and there are often numerous technologies that can be used to meet transmission needs. The Department further notes that alternative solutions can help lower, but are unlikely to eliminate, the need for traditional "poles and wires" solutions. See pages 118–119 for further discussion.

# 4. Technology

## 4.1. Alternative Transmission Solutions

Approximately 18 commenters substantively discuss the importance of GETs in meeting transmission needs. Most of these commenters suggest that DOE expand its discussion on GETs and other NWAs.

ACP, the Center for Biological Diversity, AE, AES, ACORE, and others appreciate DOE's acknowledgment of the role GETs can play in optimizing the transmission system and complementing existing grid infrastructure. AES supports DOE's needs-based, technology-agnostic approach, which includes both traditional wires and substations, as well as reconductoring and storage-as-transmission, digital improvements through DLR, topology optimization, power flow controls, and demand-side solutions.

The WATT Coalition, NEMA, LineVision, the Center for Biological Diversity, AEU, and AE encourage DOE to increase the focus on GETs and their ability to increase transmission capacity. The Center for Biological Diversity mentions that the Study fails to adequately explore NWAs as a solution to energy needs, emphasizing that NWAs should be considered the first line of offense instead of new transmission infrastructure and encourages DOE to consider the Center's comments on DOE's Grid Resilience and Innovation Partnerships Program. The WATT Coalition mentions its strong support for the following statement in the Needs Study: "When capacity expansion models find that new GW or GW-miles of transmission capacity is needed in a particular region, this could be met, at least in part, by increasing the carrying capacity of existing grid infrastructure already within the region." The WATT Coalition asserts that by adding citations to reports and studies it references in its comments, DOE can better quantify this statement. LineVision recommends a "transmission loading order approach where optimization of the grid (via the utilization of low-cost tools such as GETs) is considered first, then grid reinforcement, and then grid expansion," using customer affordability as a guiding principle. AE and the WATT Coalition recommend that the Needs Study incorporate the Study, *Unlocking the Queue with Grid-Enhancing Technologies*,[55] which found that GETs enable increased integration of renewables and lead to substantial production cost savings, emissions reductions, and economic benefits.

[55] Tsuchida T, Ross S, and Bigelow A. 2021. Unlocking the Queue with Grid-Enhancing Technologies. Available at https://watt- transmission.org/wp-content/uploads/2021/02/Brattle Unlocking-the-Queue-with-Grid-Enhancing-Technologies Final-Report_Public-Version.pdf90.pdf.

LineVision explains that utilizing DLR can also address some of the needs DOE identifies in the Study. AES discusses the various benefits of DLRs.

The WATT Coalition and other commenters recommend DOE add language that elaborates on the benefits of GETs. Referencing Section IV, the WATT Coalition notes that the report on transmission investment does not mention increased adoption of GETs by U.S. utilities and provides a list of GET deployment case studies for DOE to review.

NEMA also supports the utilization of GETs to make existing lines smarter and more efficient. It claims GETs can help satisfy immediate needs and states that NWAs should be considered on par with new transmission. For example, NEMA notes that replacing legacy steel-core wires with high-temperature, low-sag conductors allows for increased capacity through a transmission corridor and over a longer distance. NEMA mentions that combining hardware upgrades with software technologies can help to satisfy transmission needs more quickly. However, NEMA notes that modernizing existing HVDC lines alone will only generate "marginal benefits for the grid as a whole," and therefore near-term transmission development and installation is crucial for a successful energy transition.

ACORE suggests that transmission planning and interconnection studies should incorporate GETs.

AMPUA and IEDA appreciate that DOE discuss other NWAs (pages 73–75 of the Study). Furthermore, AMPUA and IEDA mention that cost comparisons of NWAs would be helpful to assist in short- and long-term planning in order to compare alternatives. AMPUA and IEDA also say that not including vegetation management as a mitigation alternative is a weakness of the Study, as they believe vegetation management is the timeliest NWA.

The Center for Biological Diversity indicates that energy efficiency is not discussed and stresses the importance of distributed energy generation and storage in meeting U.S. energy needs, stating that there is substantial technical potential of distributed solar. The Center also describes the benefits of DERs, especially paired with storage, and references several instances in which DERs powered homes and businesses during Hurricanes Maria, Fiona, and Irma. Because communities of color disproportionately bear the brunt of impacts from system failures during extreme weather events, the Center also suggests that implementing NWAs will support these communities.

NHA adds that DOE should include pumped storage in its analysis, specifically as an NWA, and states that there are NREL studies available for DOE to review. It also mentions that DOE should consider electrifying non-powered dams and marine energy as potential alternatives to new transmission lines. Xcel Energy mentions its interest in DOE broadening technology considered in the Study, including exploring long-duration battery storage.

Other specific requests include those by AMP, which suggests the NWAs section be renamed, "Advanced Transmission Technology" to align better with previous DOE reports and to incorporate high-ampacity conductors in this section. AMP explains that high-capacity conductors are not NWAs but are an advanced transmission technology, which can increase transfer capacity and provide many other benefits. AMP explains that high-ampacity conductors can ultimately save ratepayers money and reduce the need for additional

generation. AMP further claims superconductors would enable higher renewable integration. Lastly, AMP notes that many of the statements DOE has made about NWAs in the Needs Study also apply to high-ampacity conductors.

The Blue Lake Rancheria Tribe cites that transmission upgrades need to be designed with sufficient capacity for Tribal nations' DER development and other opportunities.

### Expand Discussion of Alternative Transmission Solution Benefits

Several commenters, including ACP, the Center for Biological Diversity, AE, the WATT Coalition, and others, elaborate on the benefits of alternative transmission solutions and advocate for DOE to provide further discussion benefits in the Needs Study. For instance, the Center for Biological Diversity states that the Study largely ignores the benefits of NWA, including greater affordability, greater resilience in extreme weather events, economic benefits, avoided wildlife impacts and waste of power lost in transmission, and public health benefits from displacing fossil generation. AE reiterates that GETs can complement existing grid infrastructure and optimize the amount of transmission needed. AE also mentions the importance of GETs in system optimization, reliability, increased renewable energy deployment, and supporting affordable costs for customers. The WATT Coalition reviews the benefits of GETs, including increased grid capacity, increased flexibility, greater situational awareness, reduced congestion costs, integration of low-cost generation, and maximized value of new transmission investment. Similarly, LineVision mentions the benefits of relief during outages, improved reliability, increased and flexible capacity, increased renewable integration, reduced curtailments and congestion relief, citing grid optimization efforts in New York State that recognize the benefits of advanced transmission technologies like DLR. Additionally, LineVision emphasizes that DLR technology can quickly increase transmission capacity, supporting the existing grid while new transmission is built, and therefore filling short-term needs while new transmission projects are planned over a longer-term timeline. LineVision and the WATT Coalition reference The Brattle Group's *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*[56] paper, which outlines the following benefits of GETs before, during, and after construction:

- Before: GETs can reduce congestion by at least 40%.
- During: Outages can be avoided, with similar reductions in congestion as above.
- After: Utilization on new lines can increase by 16%.

The Center for Biological Diversity references the Environmental Law and Policy Center's 2021 report on NWAs, which explains that GETs can substantially increase effective line capacity and preclude the need for additional transmission infrastructure.

[56] Tsuchida B, Bai L, and Grove J. 2023. How Grid-Enhancing Technologies Complement Transmission Buildouts. Available at https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf. .

AES specifically discusses the benefits of storage-as-transmission, including flexible peaking capacity, system stabilization, transmission congestion mitigation, renewable resource integration, and other benefits.

However, EEI highlights the limited potential of GETs, arguing that while some GETs referenced in the Needs Study—DLR, power flow controllers, and topology optimization—enable operational flexibility in the short-term, they are not replacements for transmission. EEI states that GETs "should be encouraged but not required as part of a transmission project." Further, EEI notes DLRs have limited use in planning studies.

### Barriers

A couple of commenters suggest that DOE expand its discussion on technological barriers. The WATT Coalition asserts that Section V.i Barriers to Transmission Development should include barriers to transmission optimization, such as the incentive misalignment regarding the return-on-equity business model of for-profit transmission owners and recommend citing research by Gramlich and Tsuchida, and other existing research described in item IV.c of their comments.[57]

AE specifically recommends that the Needs Study recognize the barriers that storage resources and GETs face in current transmission planning and interconnection processes, expressing their concern that Needs Study is reinforcing the inherent biases in existing transmission planning processes for traditional solutions. AE claims that assumptions used in interconnection studies poorly reflect the flexibility of storage operations, which leads to higher interconnection costs.

### Future Efforts

Some commenters recommend DOE engage in future efforts not directly related to the Needs Study. AE states that DOE should review policies that prevent the proper consideration of alternatives in transmission planning processes and requests that DOE commit additional resources to the exploration of how GETs can alleviate regional needs identified in the Study. Specifically, AE encourages DOE to fund studies that look into opportunities for GETs to alleviate transmission needs. Additionally, AE encourages DOE to perform a study that investigates how to incorporate GETs into transmission planning processes.

AEG specifically states that stored energy should be incorporated into planning, design, and deployment.

### Department Response

Commenters suggested the Department relabel Section V.h. of the draft Study to "Advanced Transmission Technologies" rather than "Non-Wires Alternatives" to be inclusive of more technologies and to be consistent with previous DOE reports on the subject. Commenters also suggested the Department incorporate advanced conductors and cables into the final Study. In response, the Department refers to both GETs and advanced conductors and cables as

[57] Tsuchida B, and Gramlich R. 2019. Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives. Available at Brattle-Grid-Strategies-Paper-ImprovingTransmissionOperationWithAdvancedTechnologies.pdf (smartwires.com).

advanced transmission technologies but relabels Section V.d. in the final Study as “Alternative Transmission Solutions” to refer to the suite of tools and technologies discussed, which also include storage, DERs, and microgrids. In addition, the Department added a subsection to *Section V.d. Alternative Transmission Solutions* dedicated to advanced conductors and cables (page 94) and their ability to increase transmission transfer capacity in both new transmission infrastructure projects and existing infrastructure rebuilds and upgrades.

Several commenters requested the Department expand its discussion of GETs to include more information regarding specific types of GETs and their associated benefits. In response, the Department has expanded *Section V.d. Alternative Transmission Solutions* (pages 89–95) in the final Study to provide more information on various GETs referenced in the draft Study. Information specific to GETs is on pages 92–94. The Department has incorporated one new reference directly recommended by commenters in the final Study that outlines the impacts of certain GETs on the power grid, benefits to ratepayers, and the ability for GETs to complement traditional transmission expansion. In all, six new references were added to the expanded *Section V.d. Alternative Transmission Solutions* in the final Study.

Certain commenters express concern that the Department is reinforcing the inherent biases in existing transmission planning processes for traditional wire solutions, while others request the Department to clarify the limited potential of GETs. The Department continues to use the "transmission" as a technology-neutral term and applies this term to both wire and non-wire transmission facilities, unless explicitly stated otherwise. The Department does, however, note in the Executive Summary, Section V.d., and Section VI that advanced transmission solutions could help reduce, but are unlikely to eliminate, the need for new “poles and wires” transmission infrastructure.

Additionally, various commenters suggested the Department expand its discussion on the barriers to alternative transmission solution deployment, including challenges related to transmission planning and interconnection processes. The Department notes a comprehensive analysis of barriers within current transmission planning and interconnection processes is beyond the scope of this Study. The Department does, however, include a recommendation that planning entities may wish to incorporate advanced transmission solutions as part of their existing planning processes into *Section I.a. How to Use This Needs Study* of the final Study.

## 4.2. Generation Resources

Several commenters provided feedback related to generation sources considered in the Needs Study. AMPUA and IEDA appreciate DOE’s acknowledgment of the role of resource diversity in enhancing resilience and encourage an “all of the above” approach to ensure grid reliability. They point out that resource diversity in ISO-NE reduced the need for new capacity by up to 17 GW and support the Study’s acknowledgment of the capacity shortfalls in MISO and WECC.

Martyn Roetter explains that much more generation capacity will be required to fully decarbonize the grid, which could be moderated by technologies such as demand management and energy storage systems. Roetter notes that more high-capacity resources will be needed in the future to guarantee grid reliability and resilience, as electrification and weather variability cause significant demand fluctuation.

The Utah Public Lands Coordinating Office discusses the value of geothermal resources, especially in stabilizing the grid as a baseload resource with the increased penetration of intermittent wind and solar. The Office also elaborates on the challenges of expeditiously developing geothermal projects.

JHI and NHA advocate for the Study to include additional discussion on hydrokinetic energy and hydropower. JHI and NHA both suggest that the Study include the benefits of hydropower and hydrokinetic energy as growing national energy resources, as well as the implications and projected economic and environmental benefits. NHA notes the potential for marine energy to serve as a potential alternative to new transmission. JHI explains that hydropower and hydrokinetic locations are sometimes far from existing grid infrastructure, making it economically challenging and financially impractical to interconnect projects. However, as the grid becomes strained, JHI and NHA argue that potential hydropower projects and associated interconnected transmission possess new national value and value proposition because they deliver firm power to support intermittent energy resources and provide national security and decarbonization enhancements. Therefore, JHI and NHA encourage DOE to consider an analysis that would identify potentially constrained hydropower projects which would be viable if additional transmission were built to access the hydropower and hydrokinetic resources. JHI references Chapter 3: Assessment of National Hydropower Potential of DOE's 2016 *Hydrovision Report*,[58] to identify untapped national hydropower resources.

Furthermore, JHI asks DOE to give more consideration to large and small fish-friendly hydropower development and requests that American-developed and -produced hydro resources receive the same consideration as other renewable resources identified in the Study. NHA also recommends that DOE consider non-powered dams that could be electrified.

Lastly, ACC argues that natural gas should be incorporated into DOE's analysis, given it is secure, reliable, and contributes to lowering emissions on the grid.

### Department Response

The Department thanks commenters for their comments related to generation resources. Given the intended focus on the transmission system, the Department has opted not to incorporate recommendations regarding discussion of specific generation resources. The Department has instead made revisions throughout to make discussion surrounding generation in the final Study to be more technology neutral, distinguishing generation technologies based on their implications for the transmission system instead of their carbon emissions. See Department Response to Section 2.4 of this comment synthesis for additional discussion on how generation diversity is framed in the final Study.

The Department acknowledges commenters' concerns that discussions of wind and solar energy heavily outweigh other generation technologies. These specific generation technologies, which are being adopted rapidly, have unique implications for the transmission system. Most

[58] U.S. Department of Energy. 2016. Hydropower Vision Chapter 3, Assessment of National Hydropower Potential. Available at https://www.energy.gov/node/1922621/.

notably, the variable nature of these resources' generation has reliability considerations that firm resources—such as natural gas, hydropower, and geothermal energy—do not. Studies have also shown that both land-based and OSW energy technologies require interregional planning that differs from many historic regional transmission planning processes. Discussion of these energy sources has been reframed in the final Study to specify implications for the transmission system.

## 4.3. Offshore Transmission

Several commenters recommend that DOE expand its discussion on OSW and offshore transmission. The PIOs highlight the lack of OSW-related transmission needs identified in the Needs Study and indicate that the Study should incorporate existing studies that identify this need.

ACP appreciates the Study acknowledging that existing transmission capacity cannot support the growing number of OSW projects, as many coastal transmission facilities are lower voltage. ACP explains that integrating OSW will drive significant upgrades to coastal transmission systems on a generator-by-generator basis, but these upgrades will not sustain the expected OSW deployment needed to meet state and federal policy goals.

A few commenters discuss the planning required for OSW development. SPIGs state that the Needs Study inadequately expresses the urgency for coordinated planning efforts needed to integrate OSW. Specifically, SPIGs recommend that DOE acknowledge the benefits of coordinated transmission development on the East Coast. SPIGs describe available OSW capacity off the coast of North Carolina and explain that a coordinated approach to OSW transmission will reduce the number of required interconnections. Additionally, SPIGs illustrate a backbone transmission system, or "an ocean grid" that would cost-effectively address the challenges of interconnecting OSW capacity to the onshore grid.[59] Con Edison states that DOE's efforts are helpful in recognizing future needs and encouraging productive discussion on coordinated transmission planning and development, especially to advance the integration of OSW. NYTOs stress the importance of a coordinated approach to OSW development, especially to optimize the use of constrained waterways in dense, urban areas. National Grid recommends that DOE examine both onshore and offshore resources when discussing interregional planning.

The Blue Lake Rancheria Tribe asserts that Tribes need to be involved early in planning for OSW transmission upgrades. The Blue Lake Rancheria Tribe claims that upgrades, planned with sufficient capacity to connect OSW to Tribal Nations, would be significantly more effective and introduce opportunities for Tribal support and transmission development. In reference to the Needs Study's Offshore Wind Section, the Blue Lake Rancheria Tribe adds that there is potential for ~15–45 GW of OSW generation off the Northern California/Southern Oregon coasts, but to deliver OSW power to load centers to the east, south, and north, new high-voltage transmission lines must be built.

[59] Levitan & Associates, Inc. 2020. Offshore Wind Transmission: Study Comparison of Options, p. 6. Available at https://www.nj.gov/bpu/pdf/publicnotice/Transmission%20Study%20Report%2029Dec2020%202nd%20FINAL.pdf.

Two commenters provide insight into OSW needs in New York. Con Edison mentions its high priority of planning for the integration of OSW, noting its current project in development—the Brooklyn Clean Energy Hub—and the need for coordinated transmission solutions to connect OSW resources to the grid. Con Edison advises DOE to consider the need to expand transmission in New York to connect OSW resources. NYTOs reference several studies by New York that indicate the benefits of developing a meshed offshore transmission network,[60,61] including discussion of offshore networks linking New York with New Jersey and New England.[62]

Similarly, PSEG supports the Study's finding that there is an immediate need for "an offshore backbone grid to support state policies for offshore wind generation," but states that the Study should also recognize the need to establish a fully networked system rather than a network-ready system. Specifically, in response to DOE's statement that "an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of (OSW) resources compared with each OSW resource connecting to the onshore grid through a dedicated generator lead line," PSEG asserts that "a network-ready system will only delay implementation and lead to increased costs later on, as technologies developed today will be obsolete or require [costly] upgrades." PSEG goes on to mention that a networked system to support OSW generation provides economic, reliability, resiliency, and other benefits. PSEG references New York State Energy Research and Development Authority's meshed grid study identifying approximately $60 million in annual savings for New York ratepayers.[63]

Several commenters encourage DOE to consider OSW needs in other regions outside of the Atlantic coast:

- ACP and the PIOs recommend DOE consider OSW as a driver of transmission in other regions of the country, such as the Gulf of Mexico, the West Coast, and the Great Lakes. PIOs suggest that DOE initiate studies to analyze how different coordinated transmission solutions would enable OSW in these regions and subsequently undertake an interim Needs Study when such regional studies are available.

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[60] New York Department of Public Service and New York State Energy Research and Development Authority. 2021. Initial Report on the New York Power Grid Study , p. 69 and 75. Available at https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/NY-Power-Grid/full-report-NY-power-grid.pdf.

[61] Pfeifenberger J, Tsoukalis J, Newell S. 2021. The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York, p. 8. Available at https://www.brattle.com/wp-content/uploads/2021/12/The-Benefit-and-Cost-of-Preserving-the-Option-to-Create-a-Meshed-Offshore-Grid-for-New-York.pdf.

[62] State of New York Public Service Commission. 2022. Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, NYPSC Case 20-E-0197, et al. Order on Power Grid Study Recommendations, p. 11. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={23F0F463-A059-4CFC-9134-4535F660611F}.

[63] Pfeifenberger J, Tsoukalis J, Newell S. 2021. The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York, p. 8. Available at https://www.brattle.com/wp-content/uploads/2021/12/The-Benefit-and-Cost-of-Preserving-the-Option-to-Create-a-Meshed-Offshore-Grid-for-New-York.pdf.

- SREA suggests that the Needs Study consider increased interregional capacity between Texas and Louisiana to integrate OSW in the Gulf of Mexico.
- SPIGs indicate that the Study has not fully explored the development of OSW in the Southeast and Mid-Atlantic and the unique transmission needs that would be required to accommodate such development.
- TDI-NE refers to studies by the Massachusetts Institute of Technology, the State of Massachusetts, and the State of Connecticut that indicate increased transmission capacity with Québec is the lowest cost option that maximizes the value of New England's OSW potential.

Several commenters suggest additional resources, related to OSW, for DOE to consider in the Needs Study. These are itemized below.

- National Grid's comments focus on integrating offshore resources on the Atlantic coast and discuss the benefits of interregional transmission, specifically related to the OSW integration. The utility references NREL's Atlantic Offshore Wind Transmission Study, recommending that DOE consider how the results of the Needs Study and NREL's study interact, especially as they relate to interregional transfers.
- PSEG recommends that DOE update the Needs Study to reflect the 40 recommendations outlined in the updated Atlantic Offshore Wind Transmission Study referred to in the Needs Study.[64]
- PIOs urge DOE to incorporate its findings from the 2021 Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis along with other relevant studies.[65,66,67,68]
- SPIGs provide several attachments as resources to DOE, including Johannes P. Pfeifenberger et al., *The Benefit and Urgency of Planned Offshore Transmission:*

[64] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Stakeholder Workshop slides 30–58. Available at https://www.energy.gov/sites/default/files/2023-04/DOE%20GDO%20AOSW%20Workshop%20Presentation%20032223%20Final_508.pdf.

[65] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis. Available at https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.

[66] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[67] Smith K, Lenney S, Marsden O, Kates-Garnick B, Stanković A, Hines E. 2021. Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets. Available at https://createsolutions.tufts.edu/wp-content/uploads/2021/08/OSW-Transmission-and-Grid-NE.pdf.

[68] PJM Interconnection. 2021. Offshore Wind Transmission Study: Phase 1 Results. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

*Reducing the Costs and Barriers to Achieving U.S. Clean Energy Goals*, The Brattle Group (Jan. 24, 2023).[69]

- ACORE recommends that DOE review and incorporate The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals into the Needs Study, which discusses how offshore transmission development can cost effectively integrate offshore wind and provide resiliency benefits to the onshore grid.[70]

#### Department Response

Several commenters recommend that DOE expand its discussion on OSW and offshore transmission and expand the Study to incorporate offshore transmission beyond the Atlantic coast. In response, the Department has included additional information related to offshore transmission in Section *V.c. Generation and Demand Changes* of the final Study (pages 81–83). New information includes a discussion of how emerging offshore energy generation industries, which require unique transmission planning with new jurisdictional questions, can result in reliability implications for connecting to the land-based transmission system. Eleven additional references were included in the final Study, most of which are either Department or industry reports and several were suggested for inclusion by commenters. Among the new resources is preliminary analysis from the Department's Atlantic Offshore Wind Transmission Study.

In response to the Blue Lake Rancheria Tribe assertion that Tribes need to be involved early in planning for OSW transmission upgrades and as noted in the Department Response of Section 1.6 above, the Department has added a discussion of the need for community, stakeholder, and Tribal engagement during the transmission development process to pages 106–108 of *Section V. Siting and Land Use Considerations* in the final Study. Additionally, the Department has recently launched the Tribal Nation Technical Assistance Program for Offshore Wind Transmission program, which offers technical assistance, trainings, and participation support funds to help Tribes successfully engage transmission planning and development for OSW in the United States.

### 4.4. Other Technologies

Some commenters mention additional technologies for DOE to consider incorporating into the Needs Study.

Xcel Energy asks DOE the following questions:

- "Is it possible to broaden the technology assumptions used for the generation resource mix to analyze the benefits of dispatchable clean energy resources? There seems to be a bias to a very heavy renewable energy future rather than a more comprehensive set of resource types, like inclusion of green hydrogen and advanced nuclear technologies.

[69] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[70] Ibid.

- Does the Study incorporate DOE funding of various hydrogen hubs throughout the country and the likely propensity of hydrogen adoption in CT and CC technologies?"

The Center for Biological Diversity notes that Grid-Interactive Efficient Buildings (GEBs) can assist with energy needs by shifting building demand to times of high peak supply, decreasing utility and customer costs, reducing the need for new transmission and distribution builds, and improving climate resilience. The Center also discusses energy efficiency initiatives, reviewing various benefits of deploying energy efficiency and conservation technologies.

To decarbonize the U.S. electricity system by 2050, AES explains that the United States cannot rely solely on new transmission builds, but also needs to support new and other market-available technologies that quickly address transmission needs. AES also lists several technology-neutral use case descriptions for DOE to reference and detail the benefits of aggregations of energy and enhanced grid visualization and simulation software.

AMP discusses the benefits of high-ampacity conductors, which include quickly increasing grid capacity, energy efficiency, and resilience, relieving underlying grid congestion, and interconnecting more clean energy. AMP emphasizes that high-ampacity conductors are advanced transmission technology that should be considered in the Study.

Martyn Roetter discusses his concerns surrounding green hydrogen and its impact on the demand for electricity. Roetter is also concerned about the definition of "clean" in the context of "clean hydrogen," as Roetter explains that green hydrogen production via electrolysis is electricity intensive.

Roetter would like DOE to confirm that Study scenarios of future grid loads of 7,000 TWh to 8,000 TWh by the 2040s do not account for demands for clean grid-connected electricity to produce green hydrogen or power carbon dioxide removal systems. Roetter assumes that load increases in the Study scenarios are largely driven by electrification of buildings and transport.

Roetter mentions that projected green hydrogen demand (22–41 million tonnes annually in the United States), will require 1,000–2,000 TWh of clean electricity. Roetter outlines the following two questions, requesting DOE to address them by utilizing future transmission scenarios derived from reliable, integrated coordinated energy planning that also considers electricity demand for purposes beyond direct delivery to end uses over the grid:

- "Do the scenarios in the Transmission Needs Study include a substantial grid load for producing hydrogen or do they assume that other dedicated sources of clean electricity not connected to the grid will be used to power the electrolysers?
- If alternatively clean electricity from the grid is used in significant quantities to produce green hydrogen, and/or for any other purpose than direct delivery to electrified applications, what will be the impact on the pace and extent of grid decarbonization over time, and hence on progressively eliminating anthropogenic emissions to achieve growing reductions in annual emissions in 2030, 2040, 2050 and subsequently?"

Similarly, SREA suggests that DOE consider the needs driven by the growth of green hydrogen and incorporate assumptions "for hourly matching of hydrogen production with renewable energy."

Additionally, Vijayasekar Rajsekar encourages DOE to expand on its consideration of the need for communications and control systems infrastructure—including advanced grid monitoring services like Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), and Inter-control Center Communications Protocol (ICCP) technologies—explaining that "a collaboration team of top power professionals, national labs engineers and SCADA/EMS vendors could effectively design and implement the best scenario for the U.S. National Grid system." Rajsekar proposes establishing a National Grid Control Center in Washington, D.C., and updating existing ISO Regional Grid Control Centers to monitor and coordinate all interregional transmission flows. Rajsekar explains in detail an approach to developing a "National Transmission Grid," which includes five phases described in his comment.

NEMA recommends that interested parties consult with manufacturers to better understand how existing technologies that are not typically considered can provide solutions to transmission needs.

#### Department Response

The Department thanks commenters for their comments regarding other technologies.

In response to requests for additional modeling or scenario assumptions in modeling, see Department Response to Section 2.4, which outlines that the Needs Study is an assessment of previously conducted analysis only and does not include new grid modeling. For additional discussion on demand-side solutions and energy efficiency, see Department Response in Section 2.2. In response to suggestions to include alternative transmission technologies and high-ampacity conductors, see Department Response in Section 4.1.

The high load growth scenarios that make up the High/High scenario group used in *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* do include scenarios with grid-connected hydrogen production. Both grid-connected hydrogen production and direct air carbon capture and sequestration technologies were primary drivers of high demand in many of these scenarios. In response to commenter questions on hydrogen, the Department added clarification that hydrogen is included on pages 116, 119, and 125. For a more detailed discussion of how hydrogen is modeled in the underlying capacity expansion studies, the Department directs the commenter to review the scenarios included in each scenario group, provided in Table S-6 (pages 40–43) of the Supplemental Material, and the source documentation specific to each relevant capacity expansion study.

The Department has determined the inclusion of communications and protection protocols identified in comments received are beyond the scope of this Study.

# 5. DOE Statutory Authority and Designation of National Interest Electric Transmission Corridors

## 5.1. Support

ACP, ACORE, CEBA, SREA, PIOs, DCC, EDF, and others all maintain that the Study is well within DOE's authority under Section 216, as amended by IIJA. EDF states that DOE has "fulfilled its

longstanding mandate" in conducting a study of congestion and capacity constraints. EDF and others confirm that DOE's definition of "transmission need" aligns with Congress's intent under FPA Section 216(a).

Similarly, PIOs explain that Section 216 does not limit DOE's analysis to existing or historical conditions, but instead outlines that DOE may designate a NIETC where there is existing *or future* transmission congestion or constraints. PIOs indicate that Section 216(a)(4) also references several factors that can be considered in NIETC designation, including national energy policy and security interests, economic growth, and diversification of resources. Because the Needs Study serves a primary role in in NIETC designation, PIOs state it is necessary for DOE to broadly assess the multiple drivers of existing and future transmission needs. Con Edison notes that although it currently takes no position on NIETC designation, it supports DOE using its findings to stimulate interregional discussions.

Several commenters, including ACORE, SREA, SPIGs, and PIOs, disagree with comments from SERTP Sponsors, who argue that the Needs Study is overly broad and exceeds the statutory provisions. ACORE asserts that such breadth is needed to demonstrate that current capacity constraints and congestion prevent the system from achieving transmission benefits, including accessing more cost-effective generation and improved reliability and resilience.

SPIGs contextualize SERTP Sponsors' comments, stating the following:

"As the utilities tasked with transmission planning in the Southeast, the SERTP is in large part responsible for the needs identified in the Draft Study and these comments. Their attempts to discredit the Draft Study's findings and diminish the Department's authority to catalogue the region's transmission needs must be viewed in the context of their historic underinvestment in regional and interregional transmission. Contrary to the assertions of SERTP Sponsors, the Department's mandates under the Federal Power Act (FPA), the IRA, and the IIJA are sufficiently broad to encompass the scope of this Draft Study, with room to spare. SERTP's unfounded criticisms should not deter the Department from releasing a fulsome assessment of the transmission system's existing deficiencies, however poorly that may reflect on the planning processes that produced them."

Similarly, EDF addresses comments to DOE made by other entities that suggest DOE has exceeded its authority by assessing future needs. EDF argues that these commenters disregard DOE's statutory obligation to produce a study that identifies expected transmission congestion and constraints. EDF claims that limiting the Study to historical conditions would conflict with congressional directive. EDF also emphasizes that "commenters suggesting that DOE should leave analysis of issues like projections of future demand and generation to 'NERC-registered transmission planners and transmission owners' would have DOE abdicate these responsibilities, which Congress specifically assigned to DOE and expanded in recent legislation."

ACP mentions that a subsequent report by DOE is necessary to designate NIETCs. ACP suggests DOE clarify that applicants may submit proposals for "narrowly tailored §216(a)(2) reports (designating a NIETC for specific lines that would address one or more needs identified in the final Needs Study)," which ACP notes is within DOE's authority.

Avangrid urges DOE to quickly proceed in designating NIETCs on a route-specific, applicant-driven basis and consider how potential corridors address unique regional needs.

Additionally, JHI notes that the scope of the Needs Study is not limited exclusively to FPA Section 216(a), and therefore should consider Alaska transmission needs.

Regarding DOE's statutory obligation "to consult with affected States, Indian Tribes and regional organizations in preparing the draft Transmission Needs Study," EDF mentions that DOE has undoubtedly met its obligation. However, EDF still urges DOE to go beyond just meeting the statutory minimum and consult with potentially affected communities and nongovernmental organizations with expertise in transmission capacity and congestion.

#### Department Response

Several commenters recommend that the Department clarify aspects of the NIETC designation process. In response, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

In response to JHI's comments regarding the inclusion of Alaska's transmission needs into the final Study, the Department has incorporated both Alaska and Hawaii into the final Study. Please see the Department Response of Section 2.3 for additional information on how these states' transmission needs were incorporated.

### 5.2. Opposition

Approximately four commenters express concern that the scope of the Needs Study exceeds DOE's authority under FPA Section 216. SERTP Sponsors provide the most substantive feedback regarding this concern, insisting that the Needs Study is overly broad, and not a reflection of the statute. SERTP Sponsors explain that although IIJA made limited changes to FPA Section 216(a)(1), DOE overly expanded the Study scope to include an analysis similar to a generation planning study, which SERTP Sponsors caution could cross over into state jurisdiction and result in inaccurate and unactionable transmission need determinations. SERTP Sponsors notify DOE that if the final Study and NIETC designation is based on the analyses presented in the draft Study, then the Department will be required to address these statutory concerns.

SERTP Sponsors also argue that FPA Section 216(a) includes certain considerations in designating a NIETC, including core economic concerns that necessitate an analysis of cost, which SERTP Sponsors imply the Needs Study omits, and therefore is unsuitable to utilize in corridor designations.

Similarly, Keryn Newman declares that DOE has not sufficiently answered the question of its authority and jurisdiction to plan the transmission system, which Newman argues is outside DOE's jurisdiction. Newman claims that DOE also does not have authority over cost allocation, arguing that transmission planning and cost allocation fall under the responsibilities of existing planning authorities. Newman elaborates that DOE's authority is restricted to the designation of corridors that shift transmission permitting from states to federal regulators.

ACC stresses that DOE should acknowledge in the Study that its principal aim is to carry out its "Congressionally delegated authority and expertise" rather than "shoehorn ancillary Administration policy goals into federal actions that are neither designed for nor compatible with a kitchen sink policy strategy."

Lastly, the NCUC reference pages 1–2 of the draft Study, stating that the listed benefits of mitigating transmission needs overstep the specific considerations for NIETCs set out in the FPA.

#### Department Response

In response to comments seeking clarity on the NIETC designation process, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion. Further, the Department has provided its statutory authority for the Needs Study and NIETC designation in *Section II. Legislative Language* (pages 6–7).

### 5.3. Designation of National Interest Electric Transmission Corridors

Many commenters provided feedback related to the designation of NIETCs. In general, comments relate to engagement with stakeholders or coordinating with other entities, requests for additional clarification on how the Needs Study will inform NIETC designation, and support or challenges to DOE statutory authority to NIETC designation.

#### Stakeholder Engagement and Coordination

Several commenters, including PJM, the Center for Biological Diversity, EDF, CEBA, and others recommend that DOE thoroughly engage with states, affected parties, industry, or other stakeholders throughout the NIETC designation process. The Center for Biological Diversity urges DOE to engage in meaningful dialogue with stakeholders before designating corridors. While it recognizes the administration's rush to build out transmission infrastructure, the Center emphasizes that meaningful community engagement and trust are crucial to effective implementation of this effort. Specifically, it encourages DOE to include trusted leaders and community-based organizations who are appropriately compensated for their work, while prioritizing those who have proven history of positive community engagement.[71] Furthermore, the Center for Biological Diversity encourages DOE to address barriers to engagement by holding meetings at times and places that maximize community turnout and provide childcare, translation services, and the option to attend virtually.[72] EDF also encourages DOE to consult

[71] California Energy Commission. Disadvantaged Communities Advisory Group, Equity Framework. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/disadvantaged-communities/dacag-equity-framework.pdf?sc_lang=en&hash=130F6FD0AEA89095CD0EAC455D0C60EE.

[72] See Initiative for Energy Justice, The Energy Justice Workbook, Section 1 – Defining Energy Justice: Connections to Environmental Justice, Climate Justice, and the Just Transition. Available at https://iejusa.org/section-1-defining-energy-justice/.

with potentially affected communities, nongovernmental organizations with expertise in transmission capacity and congestion, affected states, Indian Tribes and other relevant voices in considering NIETC designations. Similarly, DCC recommends that DOE provide additional transparency and opportunities for stakeholder and public input on the NIETC designation process, particularly ones that include large commercial and industrial customers.

Although Con Edison notes that a NIETC may not currently be needed in New York, Con Edison is supportive of DOE using Needs Study findings to encourage discussions between regions. Con Edison also urges DOE to engage with state public service commissions and stakeholders to review potential recommendations. To ensure the Needs Study and any NIETC designations are based on the best available information, SERTP Sponsors suggest that DOE coordinate with transmission planners and planning coordinators, such as the NERC-registered planning coordinators, as these entities include state load, resource projections, and cost evaluations in their transmission planning.

### Clarification on Use of the Needs Study in Informing NIETC Designation

AEU, CEBA, ACP, EEI, ACEG, PJM, and PIOs urge DOE to provide more information on how the conclusions of the Needs Study will be used to evaluate the designation of NIETCs going forward. PJM is concerned that the Study does not provide guidance on the size of the area that might be considered to address the identified capacity constraints or congestion, which makes it difficult to determine how future NIETC designations will be based on specific conclusions in the Needs Study.

EEI notes that in DOE's Building a Better Grid Initiative NOI, DOE "indicated that it intends 'to provide a process for the designation of National Corridors on a route-specific, applicant-driven basis,' with the intent of facilitating efficient consideration of projects seeking a FERC-issued permit." EEI recommends that DOE elaborate on how applicants can utilize the Needs Study in their applications (e.g., explaining when and how a project/NIETC application will be evaluated in terms of meeting customers' needs and cost-effectiveness).[73]

### DOE Statutory Authority to NIETC Designation

EDF, PIOs, DCC, and others acknowledge DOE's authority to designate NIETCs based on needs identified in the draft Study. EDF and PIOs emphasize that DOE is well within its authority to consider both historical and future needs of the system. Specifically, EDF supports DOE's definition of transmission capacity constraints, stating that the definition "aligns with the Department's role in preparing a study designed to identify NIETCs as well as in administering research and development, loan, and grant programs supporting transmission build-out and other electric system improvements." PIOs further elaborate that Section 216(a)(4) outlines several factors that can be considered in corridor designation, including national energy policy and security interests, economic growth, and diversification of resources.

[73] U.S. Department of Energy. 2022. Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization on [p. 16]. Available at https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf.

However, a few commenters express concern over using the Needs Study to inform NIETC designation. SERTP Sponsors state that because the Needs Study does not consider costs, the Study is not an appropriate basis for NIETC designation, which should also consider costs. SERTP Sponsors urge DOE to coordinate with planning entities as they perform analyses that evaluate state load and resource projections, as well as costs.

Similarly, PJM believes that because the Needs Study does not elaborate on the details of how a geographic corridor could alleviate congestion identified in the Study and what could constitute an appropriate corridor, the draft Study cannot provide a framework for NIETC designation and could lead to legal challenges questioning whether corridor designations are "arbitrary and capricious."

### Other

Additionally, CEBA encourages DOE to ensure NIETC designation efforts are consistent with FERC reforms on transmission planning and backstop siting so that transmission planning and siting processes are coordinated and do not delay transmission development further.

PSEG reminds DOE not to overlook regions with significant OSW targets—such as the Mid-Atlantic—as the Needs Study informs the designation of corridors.

### Department Response

The Department notes that while it certainly intends to engage with states, affected parties, industry, or other stakeholders throughout the NIETC designation process, it has determined further discussion of in-depth NIETC processes falls beyond the scope of this Study. As noted above, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

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# National Transmission Planning Study

## Chapter 1:

# Introduction

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

This report is being disseminated by the Department of Energy. As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Public Law 106-554) and information quality guidelines issued by the Department of Energy.

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# Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction (this chapter)** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# Acknowledgments

The NTP Study was led by the U.S. Department of Energy (DOE) Grid Deployment Office (GDO), in partnership with the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL). The following acknowledgments represent the full range of participation during this project (from 2022 to 2024), including the study coordinators, laboratory analysts and contributors, reviewers and production support team, and members of the technical review committee. Contributors provided useful analysis, data, input, and additional support throughout the project.

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The following individuals were responsible for the overall leadership of the NTP Study as well as leading the drafting, review, and editing processes.

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# List of Acronyms

| | |
|---|---|
| AC | alternating current |
| ATB | Annual Technology Baseline |
| B2B | back-to-back |
| BPS | bulk power system |
| CAISO | California Independent System Operator |
| CEM | capacity expansion model |
| CONUS | contiguous United States |
| C-PAGE | Chronological AC Power Flow Automated Generation |
| DC | direct current |
| DOE | U.S. Department of Energy |
| EIA | Energy Information Administration |
| EIPC | Eastern Interconnection Planning Collaborative |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERCOT | Electric Reliability Council of Texas |
| EUE | expected unserved energy |
| FERC | Federal Energy Regulatory Commission |
| FACTS | flexible alternating current system |
| FRCC | Florida Reliability Coordinating Council |
| GDO | Grid Deployment Office |
| GW | gigawatt |
| HVDC | high-voltage direct current |
| HOT | High Opportunity Transmission |
| IEA | International Energy Agency |
| IRA | Inflation Reduction Act |

| | |
|---|---|
| ISO | independent system operator |
| ISONE | Independent System Operator of New England |
| ITCS | Interregional Transfer Capability Study |
| km | kilometer |
| kV | kilovolt |
| LCC | line-commutated converter |
| LOLE | loss of load expectations |
| LOLP | loss of load probability |
| MISO | Midcontinent Independent System Operator |
| MT | multiterminal |
| NARUC | National Association of Regulatory Utility Commissioners |
| NASEO | National Association of State Energy Officials |
| NGA | National Governor’s Association |
| NERC | North American Electric Reliability Council |
| NEUE | normalized expected unserved energy |
| NIETC | National Interest Electric Transmission Corridors |
| NOPR | notice of proposed rulemaking |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| NYISO | New York Independent System Operator |
| P2P | point-to-point |
| PNNL | Pacific Northwest National Laboratory |
| PRAS | Probabilistic Resource Adequacy Suite |
| ReEDS | Regional Energy Deployment System (model) |
| reV | Renewable Energy Potential (model) |

| | |
|---|---|
| RTO | regional transmission operator |
| SCRTP | South Carolina Regional Transmission Planning |
| SERTP | Southeastern Regional Transmission Planning |
| SME | subject matter expert |
| SPP | Southwest Power Pool |
| TW | terawatt |
| TRC | technical review committee |
| VSC | voltage source converter |
| WECC | Western Electricity Coordinating Council |

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# 1 Introduction

In recent years, the transmission component of the U.S. electricity system has garnered increased attention, driven by a convergence of factors shaping the energy landscape. These include notable shifts in the generation resource mix toward low-carbon technologies located remotely from urban centers, a stagnation in new transmission projects over the past decade, heightened occurrences of extreme weather events prompting reevaluations of regional resource sharing, and evolving electricity demand patterns introducing new planning uncertainties for the future. These developments have underscored deficiencies in the current approach to transmission planning and development across the nation. Consequently, there have been concerted efforts at various levels—both regional and federal—to catalyze a more comprehensive and expedited consideration of transmission infrastructure within the United States. For instance, the Federal Energy Regulatory Commission (FERC) has been taking steps to improve processing times in interconnection queues, bolster transmission planning requirements, and increase the level at which electricity is transferred across regions (Federal Energy Regulatory Commission 2024; 2023). These endeavors reflect a growing collective recognition of the imperative to modernize and fortify the nation's transmission network to meet the evolving demands of a dynamic energy landscape.

To understand the transformation needed for the U.S. grid and how that future buildout might serve the nation's electric customers, the U.S. Department of Energy (DOE) Grid Deployment Office (GDO) partnered with the National Renewable Energy Laboratory (NREL) and the Pacific Northwest National Laboratory (PNNL) on the multiyear National Transmission Planning Study (NTP Study). The study sought to:

- Develop new national-grid-scale planning tools and methods that can be used by industry, especially when planning for interregional transmission capacity needs
- Identify potential transmission solutions that will provide broad-scale benefits to electric customers under a wide range of potential futures
- Inform planning processes for regional and interregional transmission
- Identify interregional and national strategies to maintain grid reliability as the grid transitions, including to a reliance on low- and zero-carbon energy resources.

The NTP Study combines innovative methods with state-of-the-art industry practices demonstrating a forward-thinking approach to understanding the role and value of transmission in future power systems. The national perspective of the study, which incorporates system-wide optimization, enables a holistic examination of transmission, assuming regulatory and institutional barriers are overcome. The study used a combination of tools—all under the principles of least-cost planning and maintaining power system reliability—to analyze multiple facets of transformative transmission expansion for the power system in the contiguous United States.

In preparing this report, DOE and the laboratories sought input from a wide variety of public participants and governments, including Tribes, state and local government

officials, and utilities. The study's engagement approach included public meetings, a laboratory-managed technical review committee, coordination with existing convener groups, and Tribal outreach.

**How can this study be used?**

The NTP Study results are not intended to replace regional or interregional planning processes or develop plans of service. DOE's intent is this study will provide insights for a broad set of parties about the role that transmission can play in regions across the country and tools and analysis that can be used in transmission planning processes, while in particular highlighting potential uses of interregional transmission. Table 1 outlines the boundaries of the study in relation to the many transmission planning activities around the country.

Table 1. Boundaries of NTP Study

| What the Study Does | What the Study Does Not Do |
|---|---|
| Link several long-term and short-term power system models to test multiple transmission buildout scenarios | Replace existing regional and utility planning processes |
| Develop and use innovative analytical approaches to evaluate resource adequacy, reliability, economics, and resilience to extreme events | Recommend specific locations or approvals for individual transmission lines or address detailed environmental or other land use issues, or cost allocation questions, that may be associated with future transmission lines |
| Provide information that can be used in existing planning processes by evaluating the impact to transmission of various scenarios | Evaluate specific transmission policies or proposed legislation |
| Test transmission options that may not be considered in current planning processes within utilities or regional planning organizations | Develop detailed plans of service or provide results that are as granular as planning done by utilities |
| Assess a range of economic, reliability, and resilience indicators for each transmission scenario considered | Evaluate industry proposed transmission projects |
| Provide companion reports describing opportunities and challenges to realizing potential transmission benefits identified by the study | Provide a roadmap for developing specific projects |

## 1.1 Background

Transmission planning is evolving in the United States and around the world as electric power systems integrate new technologies and respond to decarbonization demands and reliability needs, and as new loads are added, such as data centers or domestic manufacturing and electrified heating and transportation. Local and regional transmission planning processes play a crucial role in transmission deployment in the

United States and typically involve collaboration among utilities, grid operators, regulators, Tribal representatives, and stakeholders to assess future needs for transmission infrastructure. These processes vary greatly across the United States, driven by diverse regulatory and market structures, historical precedents, generation mix, and other geopolitical influences and technical approaches. These processes and the resulting regional transmission plans (see Appendix A for recent regional plans) provided a foundation for the NTP Study.

In addition to local and regional planning, recent national-scale studies have contributed to transmission planning in the United States by providing insights about broad geographic trends and the potential benefits of interconnecting regional power systems. The following section gives an overview of recently completed national-scale studies.

### 1.1.1 U.S. national-scale transmission studies and activities

Several recent national-scale power system studies have highlighted the relationship between a decarbonizing energy sector and the cost-effectiveness of transmission to deliver low-cost energy around the country. Given there is currently no formal central planning process for the U.S. grid, these studies have been conducted primarily by the national laboratories and by academic institutions. This section summarizes some of the essential findings and the relevant methods from those studies, starting with the DOE National Transmission Needs Study ("Needs Study" hereafter) (U.S. Department of Energy 2023), which itself summarizes many recent reports. In aggregate, these studies have helped motivate the discussion of the role and value of transmission within the power sector, which is undergoing significant changes. In addition, the national scope of these studies fills a gap in holistically analyzing the value of interregional transmission options.

DOE's Needs Study examines many public sources and studies that assess current and future needs for additional transmission infrastructure and evaluates several recent national-scale studies that considered the development of the transmission system.[2] These studies consistently indicate significant transmission growth is needed in many parts of the country, especially in scenarios with "high clean energy growth." The study notes high clean energy scenarios are most closely aligned with current state and federal laws including the Inflation Reduction Act (U.S. Congress 2022). Focusing on the "high clean energy growth" scenarios for 2035, regional needs ranged from a median of 64% (moderate demand) to 128% (high demand) increase in transmission capacity compared to 2020 transmission capacity. Interregional needs were even more significant than regional, relative to current capacity. Between the moderate-demand

[2] The studies referred to in this section are summarized in Table VI-1 of the DOE Needs Study (U.S. Department of Energy 2023): *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System* (Brown and Botterud 2021), *North American Renewable Integration Study* (Brinkman et al. 2021), *Standard Scenarios* (Cole et al. 2021), *Solar Futures Study* (DOE 2021), *Net Zero America* (Larson et al. 2021), and *Supply-Side Options To Achieve 100% Clean Electricity by 2035* (Denholm et al. 2022).

and high-demand scenarios, the median growth envisioned is an increase of 114%–412%.[3]

One of the central modeling tools used in the six studies outlined by the DOE Needs Study is a capacity expansion model, which finds the optimal mix of generation, storage, and transmission at least cost for the entire contiguous United States (CONUS) model (see Section 3.3.1 for further explanation of these models). One important advantage of these models is they can make trade-offs between building generation, storage, or transmission within a single optimization. A key disadvantage, from the perspective of evaluating transmission, is they are typically not able to consider the entire transmission network or the detailed physics that govern power flow, which limits their direct application to industry transmission planning—which relies heavily on power flow models that incorporate the detailed physics of the electric power system. Several national-scale studies seek to improve the representation of power flow and other temporal or spatial considerations by running a production cost model or a power flow model as a companion tool in the analysis of a future year or snapshot in time. For example, the North American Renewable Integration Study used a production cost model at 5-minute resolution with much of the network represented with direct current (DC) power flow.[4] But managing and running production cost and power flow models of CONUS with network details stretches computational abilities, easily reaching solver limits for memory and other parameters if all physical constraints were represented. Continuing to advance national-scale power system studies to be more applicable for industry is an active area of research, including in the contributions from the NTP Study and follow-on activities.

## 1.2 Objectives and Design of the Project

In addition to the primary objectives of the NTP Study stated previously, several related objectives were identified by stakeholders, Tribal representatives, and the study team[5] as important outcomes that will strengthen the impact of the study:

- Advancing the methodologies on multivalue transmission planning
- Integrating uncertainty on decarbonization efforts, electrical demand, and technology development
- Producing multimodel approaches that industry can use to improve its own planning processes

[3] A recent evaluation of industry load growth assumptions has seen large and rapid increases in future projections. Grid Strategies evaluated the load projections from recent FERC filings and found between 2022 and 2023, the summer peak demand growth forecast for the United States for the next 5 years grew from 2.6% to 4.7% (835 to 852 GW), driven largely by new industrial and data center loads not foreseen in many load forecasts prior to 2022 (Wilson and Zimmerman 2023).
[4] Other examples of nodal or approximately nodal representation of CONUS in transmission studies include (Bloom et al. 2020; Overbye et al. 2022).
[5] The “study team” refers to NREL, PNNL researchers, and GDO who contributed to the study. The “laboratory team” refers only to NREL and PNNL.

- Creation and expansion of datasets that support industry transmission planning.

The design of the study reflects a balance in advancing the methods of transmission planning while remaining grounded in the real-world challenges faced by industry today. The following sections describe how external engagement (Section 1.2.1) and the technical design of the study (Section 1.2.2) contributed to meeting those objectives.

### 1.2.1 External engagement

The NTP Study's external engagement efforts were designed to leverage the expertise of a broad set of entities and individuals around the country interested in the power system and to provide smaller venues where the study team could obtain feedback on study assumptions, methods, and objectives. External engagement included the following four aspects:

- **Public engagement** through public meetings and an online comment form
- Engagement with **existing convener groups**
- **Technical review committee (TRC)**, inclusive of three subcommittees
- **Outreach to Tribal Nations and Native Communities**

DOE hosted three virtual public webinars during the study to provide an overview of the study, provide updates, share results, highlight ongoing activities and developments of the analysis, and receive questions and feedback to improve the study design and communications. At the public meetings, the study team responded to questions and collected comments. Comments and questions were also collected via a public comment form on the NTP Study website and a project email address. The project team reviewed all questions and comments and considered them as the study progressed.

The NTP Study team also engaged with existing convener groups such as the Eastern Interconnection Planning Collaborative (EIPC), Western Electricity Coordinating Council (WECC), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Offices (NASEO), and the National Governor's Association (NGA). In the case of NARUC, NASEO, and NGA, the study team received suggestions for members to join the TRC. With EIPC and WECC, the study team shared technical approaches and received feedback. In addition, the study team worked with NARUC and NASEO to vet load forecast and policy assumptions with states.

#### *Technical Review Committee*

The laboratory team convened a TRC to receive input from individual participants with diverse viewpoints. This process was a key part of the public outreach for the project. Table 2 shows the makeup of the three subcommittees that compose the TRC.

The TRC for this project comprised a Modeling Subcommittee, a Government Subcommittee, and a Land Use and Environmental Exclusions Subcommittee. The Modeling Subcommittee brought together experts who could provide individual input on data, assumptions, and modeling frameworks and provide a reference for how industry

is using power system modeling. The Government Subcommittee enabled DOE to collect input from individuals at state and federal agencies who could provide feedback on how they view federal and state policy and regulatory issues in the analysis and give input on scenarios and assumptions. The Land Use and Environmental Exclusions Subcommittee included federal, state, and local wildlife, transportation, environmental, and legal experts who understood the multiple dimensions of transmission, renewable energy, and energy infrastructure development. Members of this subcommittee provided their individual views on generalized issues related to constraints on locating new transmission and generation. Tribal representatives were invited to participate in both the TRC plenary meetings and relevant subcommittee meetings. Additional specific Tribal engagement occurred as described in greater detail in Section 1.2.1.2.

Table 2. Overview of NTP Study Technical Review Committee and Subcommittees

| Modeling Subcommittee | Government Subcommittee | Land Use and Environmental Exclusions |
|---|---|---|
| • Clean energy professionals, including representatives of nongovernmental organizations (NGOs)<br>• Transmission owners/operators/developers<br>• Load-serving entities<br>• Regional transmission operators/independent system operators (RTOs/ISOs)<br>• Government and NGO clean energy organizations<br>• Academic modeling experts | • State public utility commissions<br>• State energy offices<br>• State governors' offices<br>• Regulatory experts<br>• Federal agencies | • State wildlife offices<br>• Federal land, water, and wildlife management agencies<br>• Local planners and siting offices<br>• Legal scholars |

Table 3 lists meetings of the TRC and its subcommittees. The Plenary TRC meetings were open to the public, although active participation in the meeting was reserved for TRC members.

Table 3. Summary of NTP Study External Engagement Events

| Meeting Date | Meeting Type |
|---|---|
| 05/20/2022 | Plenary TRC |
| 06/07/2022 | Modeling Subcommittee |
| 06/10/2022 | Government Subcommittee |
| 06/24/2022 | Land Use and Environmental Exclusions Subcommittee |
| 07/29/2022 | Modeling Subcommittee |
| 09/13/2022–09/20/2022 | Regional Meetings |
| 10/14/2022 | Plenary TRC |
| 10/28/2022 | Modeling Subcommittee |
| 11/04/2022 | Government Subcommittee |
| 12/02/2022 | Land Use and Environmental Exclusions Subcommittee |
| 12/07/2022–12/13/2022 | Regional Meetings |
| 02/10/2023 | Modeling Subcommittee |
| 03/24/2023 | Modeling Subcommittee |
| 04/21/2023 | Government Subcommittee |
| 05/01/2023–05/12/2023 | Regional Meetings |
| 10/17/2023 | Plenary TRC |
| 11/17/2023 | Government Subcommittee |
| 12/15/2023 | Modeling Subcommittee |
| 08/08/2024–08/22/204 | Regional Meetings |

*For a more comprehensive list including topics covered in each meeting, see Appendix B.*

The TRC engagement was not intended to build consensus or obtain approval, but rather solicited the viewpoints of individual attendees. The meetings for the TRC allowed the laboratory team to give updates on the progress of the study—typically around methodology decisions and interim results—and receive feedback in real time through surveys and during follow-up discussions (e.g., office hours and/or regional meetings). Subcommittees acted as an extension of the TRC, in which meetings were typically smaller and oriented around detailed discussions of analysis.

### *Outreach to Tribal Nations and Native Communities*

The NTP Study scenarios have potential implications for many Tribal Nations, Native Communities, and lands under Tribal governance. Though, as noted above, the study does not consider specific siting considerations, a Tribe might encourage clean energy development on its land, or it might prohibit development in culturally or environmentally sensitive areas.

The laboratory team conducted broad outreach to Tribes with the assistance of DOE's Office of Indian Energy Policy and Programs primarily through its Energy News Newsletter. The aim was to inform Tribes of the study objectives, ask about their interest in transmission issues, and invite feedback. A Tribe could do the following:

- Identify Tribal enterprises engaged in utility-scale energy development or regional transmission planning
- Describe any Tribal policies pertaining to utility-scale energy development
- Identify ways to enhance Tribal engagement in transmission planning
- Express other interests or concerns related to national or regional transmission planning.

The laboratory team engaged directly with Tribes that responded to the initial solicitation of interest and provided information about how the benefits of the NTP Study findings may inform a Tribe's energy policies.

The laboratory team did not incorporate assumptions about Tribal policy within the NTP Study scenarios and therefore did not exclude any area simply by virtue of it being Tribal land. Consequently, if a scenario indicated a need for additional wind or solar generation in a particular state or region, the new capacity presumably may be on Tribal or non-Tribal sites.

### 1.2.2 Technical design and study advancements

The NTP Study team built the modeling workflow with two key principles: least-cost planning and power system reliability. These two principles are intertwined throughout the study with a multimodel approach that enables an understanding of transmission from both a long-term planning perspective and a detailed engineering perspective.

Several advances in the NTP Study make its technical approach unique among other studies and typical regional planning. Notably, the study links models often used in disparate transmission planning processes within industry through an ambitious multimodel analytic framework. The NTP Study is distinct from other studies and planning activities in three primary ways:

- The NTP Study inherently included interregional transmission because it used a national perspective. Interregional transmission solutions are not often included in bottom-up planning actions taken by existing transmission planning organizations. However, without a national or multiregional perspective, studies may miss viable transmission expansion opportunities that can lead to significant potential systemwide savings.

- The NTP Study considered business-as-usual and ambitious scenarios that push decarbonization beyond the current emissions policies for many regions around the country. By taking this approach, the study team explored a broader set of

technologies and captured a combination of factors and opportunities than is typically considered in industry planning.

- By integrating multiple models and planning aspects, the NTP Study provides a comprehensive view of transmission and other resources. This approach enables the identification of more value streams and reliability benefits of transmission than are typically considered in transmission planning.

The technical chapters of this report provide details on the methods employed and datasets created—most of which will be available for industry as a product of this study.

### 1.2.3 Reliability, resilience, and resource adequacy in the NTP Study

Bulk power system (BPS) reliability consists of resource adequacy, operational reliability, and resilience. Figure 1 shows the elements of BPS reliability and the subcategories that fit into each, with yellow boxes around those that the NTP Study was able to consider (adapted from (NREL 2024a)). Within industry planning studies, these components can be stretched across many studies and are often siloed and narrow in scope, considering, for example, only resource adequacy from a comparison of supply and projected demand without detailed modeling of transmission flows. The technical design of the NTP Study is meant to provide a more holistic perspective on reliability than in many industry planning processes by ensuring transmission constraints are considered in all aspects of the study—from long-range planning through power flow—and models with differing spatial and temporal detail are closely coupled in data and constraints.

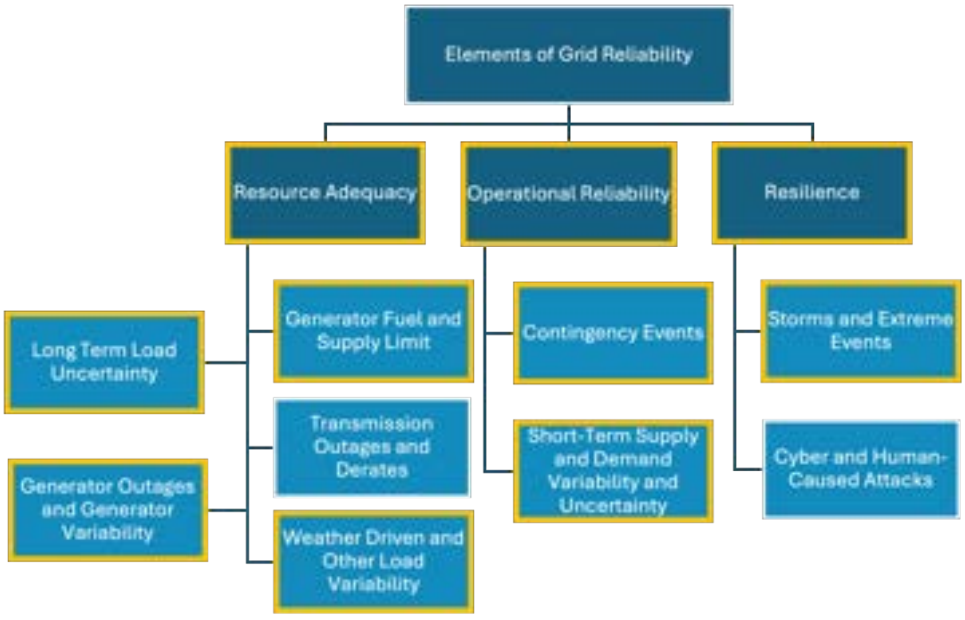


Figure 1. Elements of grid reliability

*Yellow boxes indicate the NTP Study included an evaluation of these elements.*

More detailed explanations of how the study team addressed reliability are provided in Chapters 2–5.

# 2 Study Approach

The NTP Study analysis used a combination of models and analytic tools (Figure 2) to meet the objectives outlined in the Introduction. The tools and methods are designed to reflect state-of-the-art industry practices and rigor in the level of detail and model formulations. However, the study team also made several advancements in this study to better capture and understand the role and value of transmission in future power systems. In addition, a fundamental challenge of a study that covers the entire CONUS is the scale of data that must be gathered and verified to provide meaningful results. To tackle this problem, the study team developed several techniques and datasets that will be made available to industry where possible at the conclusion of the study.

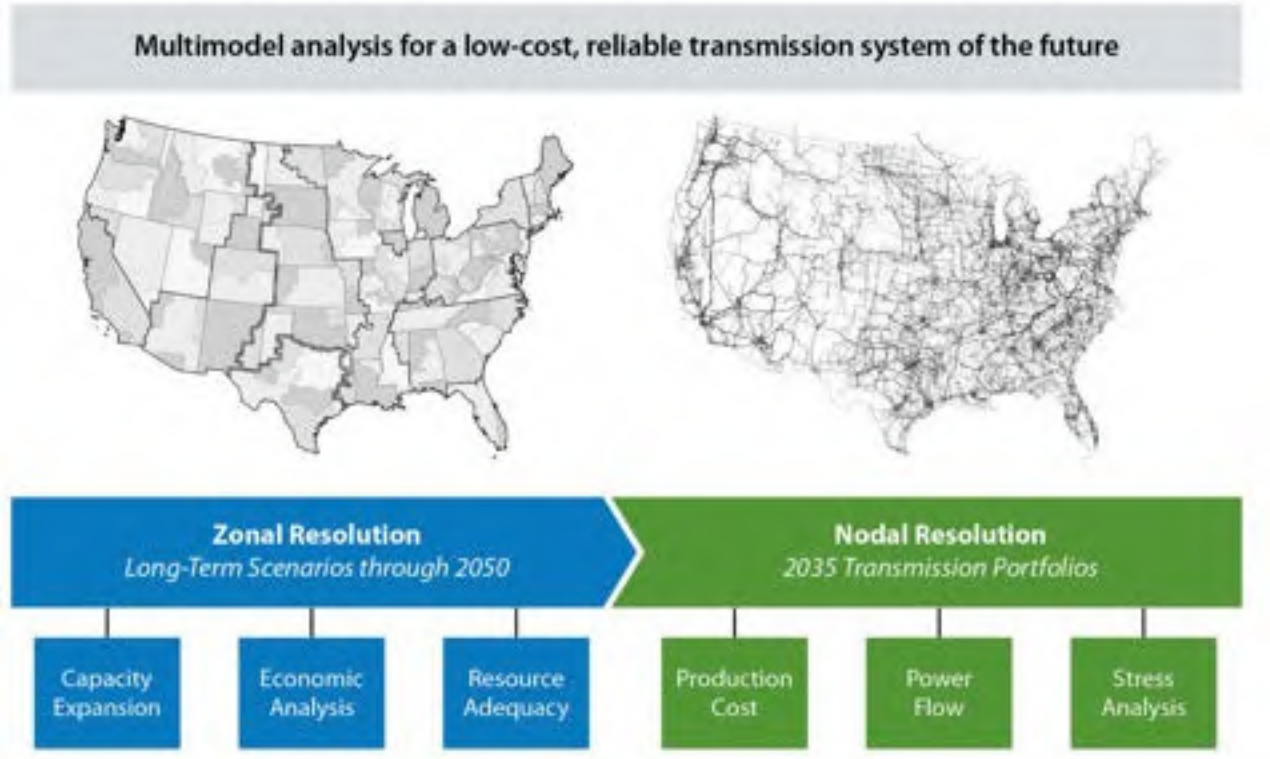


Figure 2. Modeling tools and workflow for the NTP Study

## 2.1 Capacity Expansion Model

The central tool in the NTP Study is the capacity expansion model, which the study team used to create future power system scenarios. The study team employed NREL's Regional Energy Deployment System (ReEDS) model, which chooses from a large set of new generation, storage, and transmission options to identify the systemwide least-cost portfolio that meets future demand, grid reliability, and policy requirements. For the study, the model finds the least-cost portfolio between 2020 and 2050. ReEDS applies a centralized planning approach but subdivides CONUS into 134 zones (Figure 3) to

represent the grid network and reflect region-specific characteristics of generation, demand, and policies. For investment and dispatch modeling, each solve year is represented using 33 representative days with 4-hour resolution (Brown et al. 2023). Resource adequacy is enforced in the model by including up to 30 additional "stress periods" identified by the Probabilistic Resource Adequacy Suite (PRAS), as described in Section 2.2. The ReEDS documentation (Ho et al. 2021) and 2023 Standard Scenarios report (Gagnon et al. 2024) describe the model in greater detail. Chapter 2 provides details on how ReEDS was used for this study.

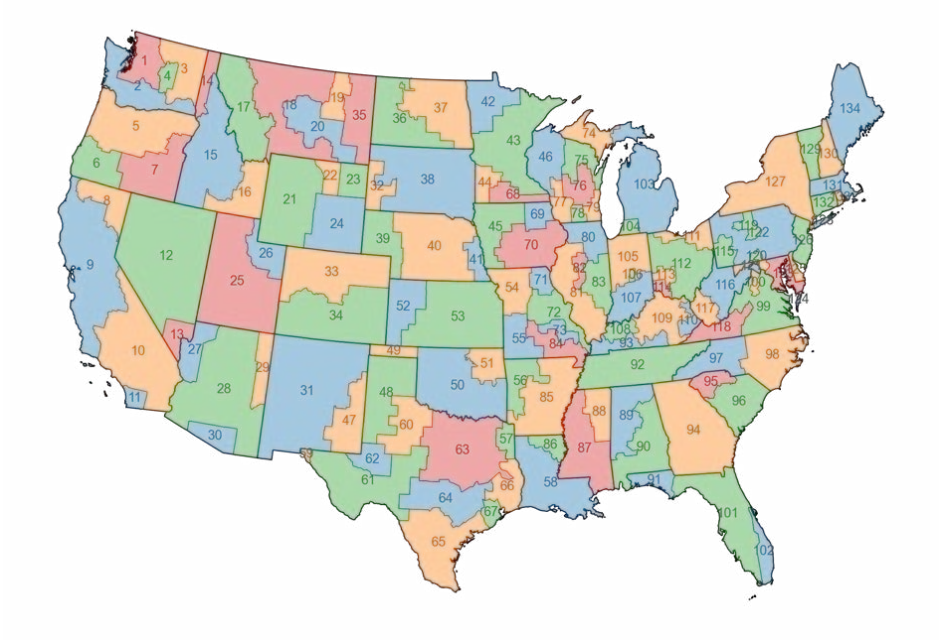

Figure 3. ReEDS 134-zone representation

### 2.1.1 Resource adequacy

The resource adequacy of the zonal scenarios (further described in Section 3) is evaluated using NREL's Probabilistic Resource Adequacy Suite (PRAS).[6] PRAS measures adequacy by performing Monte Carlo analysis of thermal generator outages[7,8] and simplified hourly dispatch over 7 weather years (2007–2013) of renewable energy availability. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy. This study focuses on the normalized expected unserved energy—expected unserved

[6] North American Electric Reliability Council (NERC) defines resource adequacy as "[t]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements" (NERC 2020).
[7] Monte Carlo analysis refers to the repeated random sampling of generator outages to represent the probability of different outcomes.
[8] Transmission outages are not modeled; however, interregional transfer capacity assumed in PRAS and ReEDS partially accounts for transmission contingencies. See Chapter 2 for more details.

energy divided by total annual load—for each modeled year for CONUS.[9] PRAS has the same CONUS scope and 134-zone resolution as ReEDS; however, thermal generator capacity within each zone is further subdivided into individual units to appropriately simulate generator outages. Chapter 2 provides additional details about PRAS.

Several advancements were achieved in this study to integrate PRAS into ReEDS, which allows for a probabilistic approach to assessing resource adequacy within the planning model. This allows for an improved assessment of resource adequacy challenges in the future systems by exposing the planning model to "higher-stress" periods. More details of this approach are provided in Chapter 2.[10]

### 2.1.2 Economic analysis

The economic analysis, which is a complement to the detailed power systems modeling, intends to answer two key questions: What are the economic benefits of transmission and who are the beneficiaries?

To identify and quantify the economic benefits of transmission, the study team used outputs from ReEDS to evaluate changes in system investment and operating costs across transmission development frameworks. The results, presented in Chapter 2, provide insights on the total systemwide benefits of transmission, the types of benefits that provide the greatest value, and how the value of transmission changes over the planning horizon.

The beneficiary analysis provides details on the distribution of transmission benefits among planning regions and different types of network users. The national ReEDS modeling is used to disaggregate benefits among transmission planning regions to identify how each region benefits from transmission and how benefits change over time and across study sensitivities (Chapter 2).

## 2.2 Production Cost Models

The study team employed production cost models in this study to verify a select set of scenarios by representing the capabilities of all individual generators, storage units, and transmission lines in an operational model run for all hours of a year. Given the increased data and computational requirements of production cost models—especially those that represent the full nodal systems for the CONUS model—the study team selected a subset of scenarios from the capacity expansion model to convert to production cost

[9] Normalized expected unserved energy is used in this study because of its effectiveness for long-term planning because it measures the broader impact of an event by incorporating the total amount of unserved energy, as opposed to only the frequency of events.

[10] Another way in which PRAS is used is by assessing the resource adequacy of systems after the full system is planned using exogenous planning reserve margins. Earlier scenarios, which were completed as an interim step within the study, used only the post-examination step with PRAS. The internal ReEDS-PRAS linkage was developed as a task within the NTP Study and applied to the final scenarios. Earlier scenarios are used for certain analyses and are called out where appropriate. Mai et al. (Brown et al. 2023) compare the approaches.

modeling datasets. The process of conversion from zonal to nodal databases required extensive methods and data development and is detailed in Chapter 3.

The production cost model used for nodal analysis of the final set of scenarios for model year 2035 is NREL's Sienna model (NREL 2024b). Sienna is used to model unit commitment and dispatch using DC power flow for the full nodal network of CONUS, with a subset of transmission line flow limits enforced based on existing known flow gates, interfaces across regional seams, and transmission buildouts adapted from the capacity expansion model scenario. More details on the construct of the Sienna nodal model, the data inputs, and the nodal scenarios are provided in Chapter 3.

In addition to Sienna, the study team also uses a commercial production cost model, Hitachi GridView, to model the Western and Eastern Interconnections for a subset of scenarios. GridView is a chronological unit commitment and economic dispatch model designed to minimize power systems' operating costs by meeting electricity demand and reserve requirements while satisfying a range of operational constraints. Scenarios modeled with GridView are presented in Chapters 3 (Section 4 only), 4, and 5.

### 2.2.1 Economic analysis using nodal transmission topologies

Within the set of scenarios selected for production cost modeling, Chapter 3 presents an analysis to evaluate economic benefits associated with system operations using GridView simulations. The analysis estimates the systemwide benefits in WECC and disaggregates them according to different network users such as generators, transmission owners, and power purchasers.

## 2.3 Power Flow

The power flow analysis explored different future network topologies for the power system by modeling alternative generation and transmission expansion options and running contingency analyses to evaluate system reliability. The study team generated the Western Interconnection power flow cases using the PNNL Chronological Alternating Current (AC) Power Flow Automated Generation (C-PAGE) tool (Vyakaranam et al. 2021).The study team identified different grid conditions using results of the production cost modeling for each scenario to test reliable operations under different loading, wind, and solar conditions that the grid will undergo throughout the year using steady-state AC power flow techniques. The study team ran tests of credible contingencies on a select set of scenarios for model year 2035.

The study team used either simple queries, such as the hour with highest flow in one of the new lines, or intelligent sampling methods to select representative hours from the production cost model for the power flow analysis. The intelligent sampling method identifies a small percentage of hourly cases that are statistically representative of the whole year and appropriate for power flow analysis. Sampling a representative number of hours allowed the study team to examine how the same contingency may have a different reliability impact on the grid based on different grid conditions while reducing the computational burden required to perform this analysis. Chapter 4 provides more details on the power flow methods.

## 2.4 Stress Analysis

To understand the impacts of grid stress conditions, the study team used the GridView production cost model to apply extreme events to the Western Interconnection. This analysis evaluates how extreme events impact the grid by simultaneously increasing demand while diminishing supply. The study team adapted several modeling tools to simulate hourly load, wind, and solar time series under varying weather conditions as well as hydropower availability during droughts for two grid stress conditions: 1) heat waves and 2) combined heat waves and drought conditions. The study team conducted economic analysis of the stress events by using value of lost load estimates to determine the cost of unserved load to end customers of the power.

## 2.5 Multimodel Datasets

Many datasets are created and used as inputs to the power system models for the NTP Study. These datasets—including electricity demand, renewable resource data, and technology and cost assumptions—are documented in greater detail in Chapters 2—5, but the following paragraph describes the core power system datasets that feed through to all the models.

The power system networks are sourced from industry power flow planning cases for the Eastern Interconnection and Western Interconnection. For the Electric Reliability Council of Texas (ERCOT), the study team compiled the data from several sources because they could not obtain a recent power flow case (see Chapter 3 for more details of the ERCOT dataset). Power flow cases are created for reliability planning and coordination within the interconnections and form the starting point for the networks developed in the production cost and power flow models developed for this study. Chapters 3 and 4 of this report provide further detail about how these datasets are used for this study. Typically, the datasets require substantial additional data about generation operations to be usable in a production cost model, which is also detailed in the technical chapters. In addition, the ReEDS model uses these data to build the zonal-level transmission network, which is presented in (Brown et al. 2023). The study team also heavily rely on data from the U.S. Energy Information Administration (EIA) (see Chapter 2 for details).

# 3 Scenarios

The power system models described previously are used to generate and assess different scenarios of the U.S. electricity system. Specifically, the ReEDS capacity expansion model is used to analyze how the system might evolve from today through 2050, based on a certain set of assumptions, whereas most of the other models are used to analyze future portfolios identified by ReEDS. The production cost modeling, power flow, and stress case analyses focus on particular 2035 portfolios.

## 3.1 Transmission Frameworks

The scenarios are designed to assess the impacts of greater transmission expansion on the future resource mix, cost and economic metrics, and reliability. These impacts are measured against a reference scenario with more limited transmission expansion that approximately reflects a continuation of the current pace of transmission development over the next several decades. The counterfactual is referred to as the Limited (Lim) transmission framework, which includes two constraints on future transmission expansion: 1) no new interregional transmission and 2) an annual limit on total transmission builds.

Interregional transmission refers to transmission between the 11 planning regions, which are based approximately on the FERC Order No. 1000 regions[11] and ERCOT, as shown by Figure 4. In the Limited framework, transmission expansion is allowed *within* each planning region, including between different zones in a planning region or for spur lines or other network upgrades for new generation interconnections. However, the annual limit constrains total transmission—of all types—based on the maximum annual builds over the past decade, estimated to be 1.83 terawatt (TW)-mile/year.

[11] The South Carolina Regional Transmission Planning (SCRTP) region from FERC Order No. 1000 is included in the Southeastern Regional Transmission Planning (SERTP) in the analysis. Nonenrolled members of FERC planning regions and regions that are not part of FERC Order No. 1000 are included within the geographic boundaries shown in the figure. The models in this study reflected the Florida panhandle as part of SERTP, though it is now part of Florida Reliability Coordinating Council.

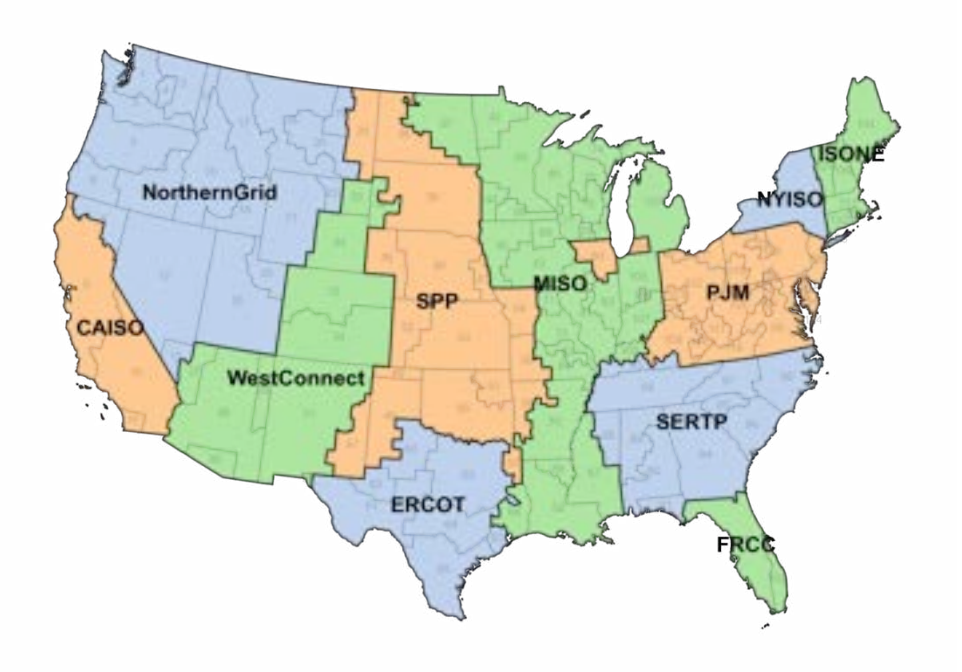


Figure 4. Planning regions

*Regional acronyms: California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Independent System Operator of New England (ISONE), Southeastern Regional Transmission Planning (SERTP), Florida Reliability Coordinating Council (FRCC).*

Additional scenarios are created with alternative transmission frameworks that relax the constraints to transmission development applied in the Limited framework. In these transmission frameworks, interregional transmission expansion is allowed and no annual limit on transmission builds is applied. However, given uncertainties about future transmission technologies, transmission cost, and degree of coordination, three distinct frameworks (AC, Point-to-Point, and Multiterminal) are used in addition to the Limited framework.

The AC framework allows transmission expansion between all adjacent zones that are within the same interconnection. Transmission costs and losses are based on AC technologies. The Point-to-Point (P2P) and Multiterminal (MT) frameworks allow the same transmission expansion options as in the AC framework but include additional HVDC options and allow interconnection seam-crossing transmission. The P2P framework includes 195 candidate connections between nonadjacent zones that are within 1,000 miles. The MT framework does not include such long-distance high-voltage direct current (HVDC) options but enables more flexibly sized multiterminal converters. Figure 5 illustrates how the four transmission frameworks are represented in ReEDS; Chapter 2 (Section 2) discusses additional assumptions and other implementation details. How these various transmission frameworks and scenarios are represented in other models differs—including choice of transmission technology (AC vs. DC) options—from what is reflected in ReEDS. This includes using a detailed transmission planning method to translate the zonal ReEDS results into individual transmission elements as described in Chapter 3 of this report.

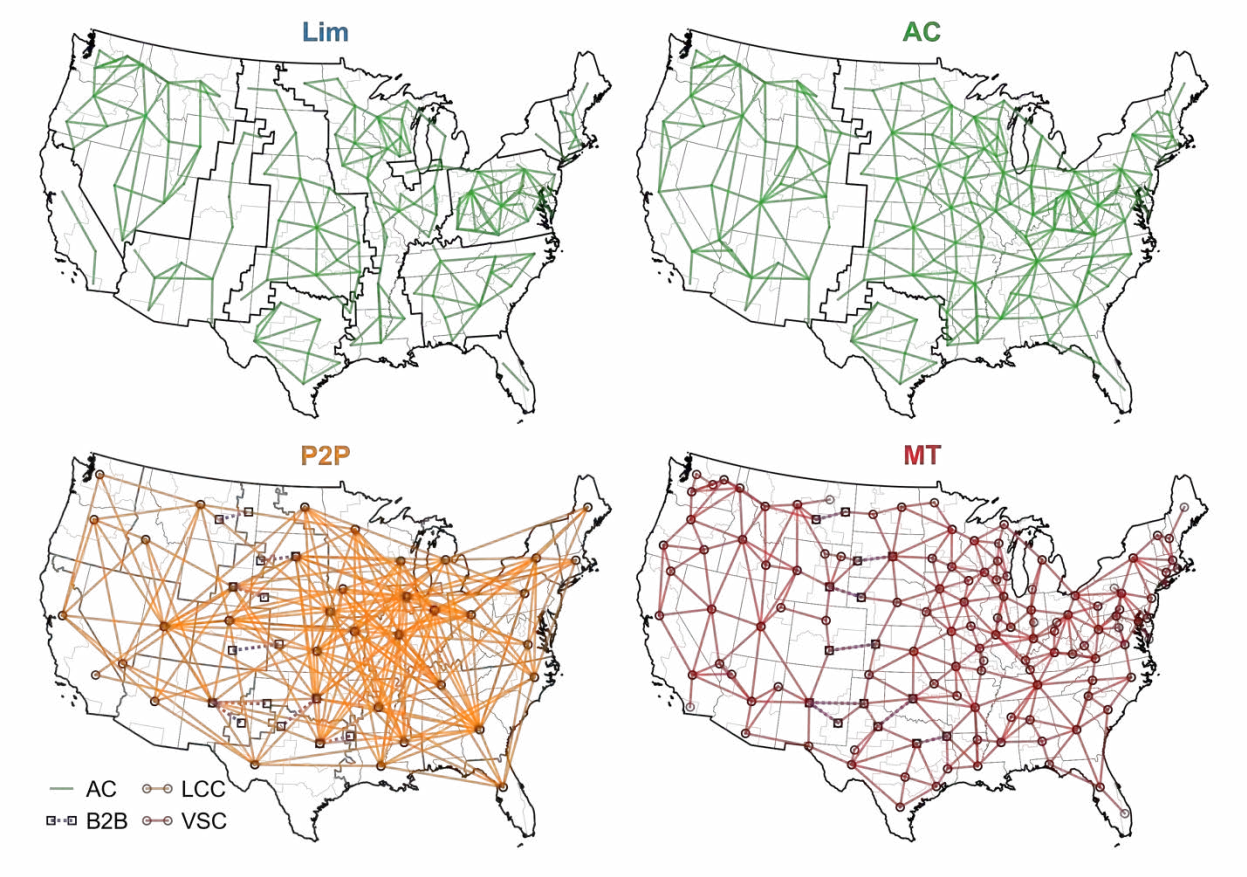


Figure 5. Transmission frameworks

*Maps show interfaces where transmission capacity can be expanded under the corresponding transmission framework. AC interfaces in the AC framework are also allowed to be expanded in the P2P and MT frameworks but are not shown for clarity. Existing transmission interfaces are not shown. Allowable transmission types are AC (green), HVDC with line-commutated converters (LCC, orange), HVDC with voltage source converter (VSC, red), and back-to-back interties (B2B, purple dashed).*

## 3.2 Scenario Design

Comparing results from scenarios under the accelerated transmission frameworks (AC, P2P, MT) with the Limited framework reveals the impact of greater transmission expansion. However, these impacts can depend on other factors, such as level of decarbonization, demand growth, and other technology and market conditions. The scenario design includes 36 “core” scenarios, which include all combinations of four transmission frameworks (Figure 5), three demand growth projections, and three levels of power sector emissions (Figure 6).

Figure 6. Core demand and emissions scenarios

*The central demand and emissions scenario is highlighted in yellow. "Current policies," "90 by 2035, 100 by 2045," and "100 by 2035" refer to emission constraints.*

Demand growth assumptions include the Low-Demand case where U.S. load grows by 0.9% per year on a compound annual basis from 2021 to 2050. The Mid- and High-Demand cases have much greater load growth (2.0% per year and 2.7% per year, respectively) because of more significant electrification projections. This electrification—driven largely by electric vehicle adoption and electrified heating in buildings—also yields changes to demand profiles with more pronounced increases in winter peaks in many regions. The three demand cases span a wide range to capture the significant uncertainties with future load growth and diversity of expectations from regional planners.

All scenarios model enacted policies as of June 2023. These policies include state clean and renewable energy standards and federal clean energy tax incentives from the Inflation Reduction Act (IRA). Under the Current Policies scenarios, no other constraints on power sector emissions or incentives for clean electricity are assumed. In contrast, the study team included decarbonization scenarios that apply a national emissions constraint. In the central decarbonization scenarios, national power sector $CO_2$ emissions are required to reduce by 90% (from 2005 levels) by 2035 and fully (100%) by 2045 and assumes Mid-Demand growth. In the most ambitious decarbonization scenarios (100% by 2035), it is assumed grid emissions are fully eliminated by 2035.

In addition to the core scenarios, there are 15 sensitivities included, each modeled for all four transmission frameworks. All the sensitivities assume central decarbonization conditions (90% by 2035 power sector emissions trajectory and Mid-Demand growth). The dimensions considered by the sensitivities include technology costs, availability of nascent technologies, renewable energy siting, costs and challenges with (transmission and pipeline) infrastructure development, and climate change impacts. Chapter 2 (Section 2) describes these sensitivities in greater detail along with a description of the other assumptions used by default. The capacity expansion analysis models a total of 96 scenarios.

## 3.3 Scenario Design Process for Multifidelity Modeling

The above-described scenario framework was developed through an iterative process with feedback from the NTP Study TRC and other stakeholders throughout the multiyear study (Section 1.3.1). This feedback included current system plans and the associated assumptions used by regional electric system planners, interpretations of enacted state policies, and expectations of key drivers and uncertainties with future system evolution. Data availability along with computational and analytic tractability constrained the incorporation of all feedback; however, the scenario design is intended to address many of the topics of interest to NTP Study stakeholders. Although none of the scenarios represents a prediction of the future state of the U.S. electric system nor aligns perfectly with any individual stakeholder's expectations, the full suite of scenarios encompasses a broad range of possibilities. The ultimate scenario framework, described previously, is designed to inform key drivers related to transmission expansion and how robust they may be to future conditions.

The study team analyzed the entire set of 96 scenarios with the capacity expansion and resource adequacy models used in the NTP Study; however, only a limited number of scenarios were evaluated with the full suite of tools described in Section 2 because of their large number, complexities with model translations, and difficulties in setting up higher-fidelity models. For the most resource-intensive modeling components of the study, such as the AC power flow modeling (Chapter 4) and the stress analysis (Chapter 5), the scenarios analyzed relied on earlier rounds of the iterative scenario design process to enable sufficient time to build those models. The following clarifies the scenarios evaluated for each class of analyses conducted within the NTP Study.

### 3.3.1 Zonal capacity expansion and resource adequacy

The capacity expansion modeling analysis and results using the ReEDS model provides the starting point for the NTP Study analysis. ReEDS is a zonal model, representing CONUS using 134 zones, that finds the optimal resource mix over time through 2050. ReEDS and PRAS—the resource adequacy model—are integrated and share the same zonal structure (Chapter 2, Section 2.2). These two models are used to examine all the scenarios and their associated assumptions presented previously. The key findings from this analysis are presented in Chapter 2. Chapter 2 also presents an analysis of subregional High Opportunity Transmission (HOT) interfaces, which is based on the same zonal analysis from ReEDS. Specifically, this analysis relies on the full suite of sensitivities.

### 3.3.2 Nodal production cost modeling

A subset of the future scenarios developed by the zonal ReEDS model is further evaluated at nodal resolution with higher-fidelity modeling of system operations. This translation to nodal resolution relies on the disaggregation of generators and storage to individual units as well as the completion of a complex transmission planning analysis (Chapter 3). The study team completed the translation for three of the core scenarios, all using the central 90% by 2035 and Mid-Demand assumptions (Figure 6). The three scenarios include the Limited, AC, and MT transmission frameworks; only the projected

2035 portfolios from those are translated. The translations enabled CONUS-wide production cost modeling using the Sienna model. Key findings from this analysis are presented in Chapter 3.

Chapter 3 also includes additional production cost modeling, using the GridView model, that supplements the CONUS-wide modeling. This modeling includes an earlier version of the scenarios similar to those described in Section 3.2.

### 3.3.3 Nodal system security and resiliency analysis

The study team conducted additional modeling at nodal resolution to examine issues regarding system security and resiliency. This analysis required the completion of a similar zonal-to-nodal translation process—as for the production cost modeling—but also required computationally intensive processing to set up the analyses. Chapters 4 and 5 describe these processes for the power flow and stress tests, respectively. As a result of these additional processing requirements, these analyses started before the completion of the final capacity expansion scenarios described previously. Instead, they relied on earlier versions of the scenarios. The main differences between these earlier scenarios and the ones presented previously (and used in Chapter 2) are summarized in Appendix C.

Overall, the final scenarios use more up-to-date assumptions and improved model advancements; however, the same broad trends observed —including renewable and carbon-free electricity share—are similar between the scenario versions. Chapters 3–5 present results from the earlier scenarios, including their resulting portfolios, used for the analyses in these chapters.

# 4 Report Structure

The NTP Study modeling and analysis report contains six chapters. These chapters together represent the entirety of the multimodel framework discussed in Section 3 and should be considered as a single NTP Study. Though the chapters are distinct, the teams and individuals contributing to the report had consistent touchpoints and shared resources, data inputs, and feedback across multiple levels of modeling.

The chapters are arranged in succession similar to how the models are linked and data flow through the project—from Chapter 2, Long-Term U.S. Transmission Planning Scenarios, to Chapter 3, Transmission Portfolios and Operations for 2035 Scenarios, to Chapter 4, AC Power Flow Analysis for 2035 Scenarios, and finally to Chapter 5, Stress Analysis for 2035 Scenarios. Each chapter has a substantial amount of technical detail and findings specific to the modeling and analysis done within that chapter. Table 4 summarizes the contents of the chapters.

Table 4. Chapter Contents

| **Chapter** | **Summary of Contents** |
|---|---|
| 1: Introduction | • Background and context<br>• Technical design of study and modeling framework<br>• Introduction to scenario framework |
| 2: Long-Term U.S. Transmission Planning Scenarios | • Methods for capacity expansion and resource adequacy<br>• Key findings from scenario analysis, including findings on resource adequacy<br>• Key findings from long-term regional economic analysis<br>• Subregional High Opportunity Transmission interface analysis |
| 3: Transmission Portfolios and Operations for 2035 Scenarios | • Methods for translation from zonal scenarios to nodal network-level transmission portfolios<br>• Network transmission portfolios for a subset of scenarios<br>• Key findings from transmission portfolio design and production cost modeling for CONUS<br>• Western Interconnection deep dive analysis of earlier scenarios |
| 4: AC Power Flow Analysis for 2035 Scenarios | • Methods for translating from zonal and nodal production cost models to AC power flow models<br>• Contingency analysis for a subset of scenarios |
| 5: Stress Analysis for 2035 Scenarios | • Methodology for developing stress scenario using the nodal transmission portfolios<br>• Key findings from stress test production cost analysis<br>• Economic analysis to compare between different stress cases |
| 6: Conclusions | • Discussion of findings and lessons learned |

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# Appendix A. Regional Transmission Planning in the United States

There are several planning exercises within regions that may contribute to the overall transmission plan of a region. Utilities carry out planning for their local areas based primarily on reliability needs. Local transmission plans are then incorporated into the regional plans. Regional planners use the local plans as a starting point to evaluate the needs for the region. Typically, regional planning is carried out on a 1- to 3-year cycle that assesses near- to mid-term needs (ACEG 2023; Eto 2017).[12] Reliability is the foremost priority in local and regional planning, although varying degrees of consideration are also given to economic and policy-related benefits across different regions. In addition, several regional planners also perform longer-term planning studies that evaluate different scenarios of load and resource mix, although these are less common among the regional planners (ACEG 2023).

In a review of recent regional plans, the study team found that every region uses power flow (or load flow) tools for planning. Most also use some form of production cost or market modeling software. Almost all regions use at least a 10-year planning horizon, with a few looking out further to 15 or 20 years; with Independent System Operator New England (ISO-NE) also recently publishing a 2050 study (ISO-NE 2024). Table A-1 provides a list of recent regional transmission plans.

[12] Typical regional planning follows principles from Order Nos 890 and 1000 (Eto and Gallo 2017).

Table A-1. Recent Regional Transmission Planning Documents

| **Federal Energy Regulatory Commission (FERC) 1000 and Electric Reliability Council of Texas (ERCOT)** | **Latest Regional Plan Accessed** | **URLs to Regional Plans (accessed May 2024)** |
|---|---|---|
| California ISO (CAISO) | 2023 | https://www.caiso.com/Documents/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf |
| ERCOT | 2023 | https://www.ercot.com/gridinfo/planning |
| Florida Reliability Coordinating Council (FRCC) | 2022 | FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf |
| ISONE | 2023 | https://www.iso-ne.com/system-planning/system-plans-studies/rsp |
| Midcontinent ISO (MISO) | 2024 | https://www.misoenergy.org/planning/long-range-transmission-planning/ |
| NorthernGrid | 2023 | https://www.northerngrid.net/private-media/documents/2022-23_Regional_Transmission_Plan.pdf |
| New York ISO (NYISO) | 2023 | https://www.nyiso.com/cspp |
| PJM | 2022 | https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx |
| Southeastern Regional Transmission Planning (SERTP) | 2023 | http://www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf |
| South Carolina Regional Transmission Planning (SCRTP) | N/A | https://www.scrtp.com/assets/pdfs/document-library/attachment-k-to-stakeholders.pdf |
| Southwest Power Pool (SPP) | 2023 | https://www.spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf |
| WestConnect | 2023 | https://doc.westconnect.com/Documents.aspx?NID=20635&dl=1 |

# Appendix B. Stakeholder Meetings

Table B-1. Stakeholder Engagement Meetings During the NTP Study

| Date | Meeting Type | Meeting Purpose |
|---|---|---|
| 3/15/2022 | Public Meeting | Officially kick off the National Transmission Planning Study |
| 05/20/2022 | Plenary Technical Review Committee (TRC) | Provide project overview and details on modeling activities. |
| 06/07/2022 | Modeling Subcommittee | Discuss methodology in developing baseline cases. |
| 06/10/2022 | Government Subcommittee | Discuss methodology in developing baseline cases and request feedback on state policy assumptions for the study. |
| 06/24/2022 | Land Use and Environmental Exclusions Subcommittee | Discuss baseline assessment and scenario tasks as well as an introduction to the Interregional Regional Energy Zones (IREZ) methodology. Subcommittee requested to provide preferences through an online survey. |
| 07/29/2022 | Modeling Subcommittee | Provide updates on baseline analysis, overview of scenario task and content, presentation of capacity expansion model draft candidate scenarios, and zonal analysis of test scenarios. |
| 08/26/2022 | Office Hours | Open to all TRC members and subject matter experts (SMEs) for the project team to answer any clarifying questions. |
| 09/13/2022 | West Regional Meeting | Regional meetings were open to TRC members and SMEs within the specific region or to multiple regions if overlap occurred. These meetings included regionally focused project updates and results. |
| 09/16/2022 | Central Regional Meeting | |
| 09/19/2022 | Southeast Regional Meeting | |
| 09/20/2022 | Northeast Regional Meeting | |
| 10/14/2022 | Plenary TRC | Provide updates on modeling framework overview and upcoming plans for federal and state policies; key findings and supporting evidence of initial candidate scenarios; Western Interconnect baseline results and power flow analysis introduction; brief updates on zonal-to-nodal analysis, IREZ, and the economic analysis tasks. |

| Date | Meeting Type | Meeting Purpose |
|---|---|---|
| 10/21/2022 | Public Update Meeting | Provide updates on the scenario analysis, receive questions, and point the public to the comment form on the project website. Questions asked during the webinar were used to inform the Frequently Asked Questions section of the project website. |
| 10/28/2022 | Modeling Subcommittee | Provide overview of the Renewable Energy Potential (reV) model and the IREZ task; update on zonal-to-nodal analysis. |
| 11/04/2022 | Government Subcommittee | Provide overall project updates; capacity expansion scenarios down-selection for nodal modeling; deeper dive into IREZ analysis; introduction to cost-benefit approach. |
| 12/02/2022 | Land Use and Environmental Exclusions Subcommittee | Provide overall project updates; capacity expansion scenarios down-selection for nodal modeling; zonal-to-nodal deep dive; introduction to resource adequacy task. |
| 12/07/2022 | Northeast Regional Meeting | Regional meetings were open to TRC members and SMEs within the specific region or to multiple regions if overlap occurred. Provide regionally focused project updates and results. |
| 12/08/2022 | West Regional Meeting | |
| 12/09/2022 | Central Regional Meeting | |
| 12/13/2022 | Southeast Regional Meeting | |
| 02/10/2023 | Modeling Subcommittee Meeting | Share project status updates (e.g., round 2 of capacity expansion model [CEM] analysis); overview of the zonal-to-nodal workflow and methodology; review of selected zonal-to-nodal results. |
| 03/03/2023 | Office Hours | Open to all TRC members and SMEs for the project team to answer any clarifying questions. |
| 03/24/2023 | Modeling Subcommittee | Provide overview of the zonal-to-nodal results broken down by region (i.e., East and West presentations); review of stress cases. |
| 04/21/2023 | Government Subcommittee | Provide modeling and process updates; overview of *Regulatory Pathways Paper* concept; overview of economic analysis. |

| Date | Meeting Type | Meeting Purpose |
|---|---|---|
| 05/01/2023 | Southeast Regional Meeting | Regional meetings were open to TRC members and SMEs within the specific region or to multiple regions if overlap occurred. Provide regionally focused project updates and results. |
| 05/03/2023 | Central Regional Meeting | |
| 05/11/2023 | Northeast Regional Meeting | |
| 05/12/2023 | West Regional Meeting | |
| 8/1/2023 | Public Meeting | Provide a progress update on the study, solicit and answer questions from participants, and direct participants to the comment form in the project website. |
| 10/17/2023 | Plenary TRC | Provide general project updates; modeling framework review; capacity expansion modeling updates; stress cases and economic analysis. |
| 11/17/2023 | Government Subcommittee | Provide modeling and project timeline updates; review of *Regulatory Pathways Paper* concept and task updates; updates on the following analyses tasks: resource adequacy, extreme events, and economics. |
| 12/15/2023 | Modeling Subcommittee | Review *High Opportunity Transmission Analysis*; provide updates on zonal-to-nodal production cost modeling; provide updates on power flow analysis. |
| 08/08/2024 | Central Regional Meeting | Regional meetings were open to TRC members and SMEs within the specific region or to multiple regions if overlap occurred. Provide a preview of final results. |
| 08/13/2024 | Northeast Regional Meeting | |
| 08/15/2024 | West Regional Meeting | |
| 08/22/2024 | Southeast Regional Meeting | |

# Appendix C. Scenario Versions

Table C-1 summarizes the major differences between the final scenarios (described in Sections 2.1–2.2, used in the scenario analysis from Chapter 2, and used for the contiguous United Stated (CONUS)-wide production cost modeling in Chapter 3) and earlier scenarios (used in the GridView modeling from Chapter 3, Section 4, and the analyses in Chapters 4–5).

Other differences not listed here are summarized in the National Renewable Energy Laboratory (NREL) 2023 Standard Scenarios (Gagnon et al. 2024), where the final scenarios are largely based on the Regional Energy Deployment System (ReEDS) model version and assumptions used in the 2023 Standard Scenarios Mid-Demand case; earlier scenarios are largely based on the 2022 version (Gagnon et al. 2022).

Table C-1. Differences Between Scenario Versions

| **Topic** | **Earlier (round 1) Scenarios**<br>Used in Chapters 4 and 5; Chapter 3 (Section 4 only) | **Final (round 2) Scenarios**<br>Used in Chapters 2 and 3 | **Notes** |
|---|---|---|---|
| Time resolution | 17 seasonal-diurnal time slices | 33 representative days at 4-hour resolution | (Brown, Cole, and Mai forthcoming) |
| Resource adequacy | Seasonal planning reserves and capacity credit | Combined ReEDS-Probabilistic Resource Adequacy Suite (ReEDS-PRAS) modeling with up to 30 stress periods | (Brown, Cole, and Mai forthcoming) |
| Hydrogen modeling | Exogenous fuel costs ($20/MMBtu) for zero-carbon renewable energy combustion turbines | Endogenous modeling of electrolytic hydrogen production, storage, and use in combustion turbines | |
| Policies | State and federal policies as of May 2022, which did not include the IRA tax incentives | State and federal policies as of June 2023, including the tax credits from the Inflation Reduction Act (IRA) | |
| Demand growth | Two demand scenarios with load growth of 0.9%/year and 2.4%/year | Three demand scenarios (Section 3.3) with load growth of 0.9%/year, 2.0%/year, and 2.7%/year | Additional state-level calibration was applied to the final demand scenarios using 2021 Energy Information Administration (EIA) data; the Mid-Demand assumptions from the final scenarios included the impacts of the IRA (see Chapter 2 for details) |
| Technology projections | ATB 2022 Moderate case | Annual Technology Baseline (ATB) 2023 Moderate case, with sensitivities using the Advanced case | (National Renewable Energy Laboratory 2022; 2023) |
| Limited transmission framework | No interregional transmission expansion and no annual cap on new transmission expansion | No interregional transmission expansion and an annual cap on total new transmission expansion | The final scenarios result in greater differences between the Limited and other transmission frameworks |

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# National Transmission Planning Study

## Chapter 2:

# Long-Term U.S. Transmission Planning Scenarios

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

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# Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios (this chapter)** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study:

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# List of Acronyms

| | |
|---|---|
| AC | alternating current |
| AEO | Annual Energy Outlook |
| APC | adjusted production cost |
| ATB | Annual Technology Baseline |
| B2B | back-to-back |
| BECCS | bioenergy with carbon capture and storage |
| CAISO | California Independent System Operator |
| CCS | carbon capture and storage |
| $CO_2$(e) | carbon dioxide equivalent |
| Coal-CCS | coal + carbon capture and storage |
| CSP | concentrating solar power |
| CT | combustion turbine |
| CTS | $CO_2$ transport and storage |
| DAC | direct air capture |
| DC | direct current |
| dGen | Distributed Generation Market Demand model |
| DOE | U.S. Department of Energy |
| EIA | Energy Information Administration |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| EUE | expected unserved energy |
| FERC | Federal Energy Regulatory Commission |
| FRCC | Florida Reliability Coordinating Council |
| GADS | Generating Availability Data System |

| | |
|---|---|
| GCM | global climate model |
| GET | grid-enhancing technologies |
| GHG | greenhouse gas |
| GW | gigawatt |
| $H_2$-CT | hydrogen combustion turbine |
| HOT | high opportunity transmission |
| HVDC | high-voltage direct current |
| IRA | Inflation Reduction Act |
| ISO | independent system operator |
| ISONE | ISO New England |
| kg | kilogram |
| km | kilometer |
| kV | kilovolt |
| kW | kilowatt |
| LBNL | Lawrence Berkeley National Laboratory |
| LCC | line-commutated converter |
| LCOE | levelized cost of energy |
| Lim | Limited (transmission framework) |
| LOLE | loss of load expectations |
| LOLP | loss of load probability |
| m | meter |
| MISO | Midcontinent Independent System Operator |
| MMT | million metric ton ($CO_2$) |
| MT | multiterminal |
| MW | megawatt |

| | |
|---|---|
| MWh | megawatt-hour |
| MW-mile | megawatt-mile |
| NARIS | North American Renewable Integration Study |
| NEMS | National Energy Modeling System |
| NERC | National Electric Reliability Corporation |
| NEUE | normalized expected unserved energy |
| NG-CC | natural gas combined cycle |
| NG-CT | natural gas combustion turbine |
| NPV | net present value |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| SMR | small modular reactor |
| NYISO | New York Independent System Operator |
| P2P | point-to-point |
| POI | point of interconnection |
| ppm | parts per million |
| PRAS | Probabilistic Resource Adequacy Suite |
| PV | photovoltaic |
| RA | resource adequacy |
| ReEDS | Regional Energy Deployment System |
| RTO | regional transmission organization |
| reV | Renewable Energy Potential |
| RPS | renewable portfolio standard |
| SCRTP | South Carolina Regional Transmission Planning |
| SERTP | Southeastern Regional Transmission Planning |

| | |
|---|---|
| SMR | small modular reactor |
| SPP | Southwest Power Pool |
| Sup3rCC | Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts |
| TES | thermal energy storage |
| TW | terawatt |
| TWh | terawatt-hour |
| TW-mile | terawatt-mile |
| VRE | variable renewable energy |
| VSC | voltage source converter |
| W | watt |
| WECC | Western Electricity Coordinating Council |

# Chapter 2 Overview

Accelerating transmission expansion can offer benefits for the contiguous U.S. electricity system under a wide range of future uncertainties. The potential role and impacts of transmission expansion are evaluated in this chapter of the National Transmission Planning Study (NTP Study). The chapter presents the methods, assumptions, and findings from the zonal analysis of long-term U.S. transmission planning scenarios. The analysis compares a "Limited" transmission framework, which constrains transmission expansion, against three accelerated transmission frameworks: Alternating Current (AC), Point-to-Point (P2P), and Multiterminal (MT) (Figure I). Because future transmission expansion can vary depending on external conditions, the analysis compared scenarios across all four transmission frameworks under a range of policy, demand growth, and other conditions. The analysis includes an assessment of 96 total scenarios.

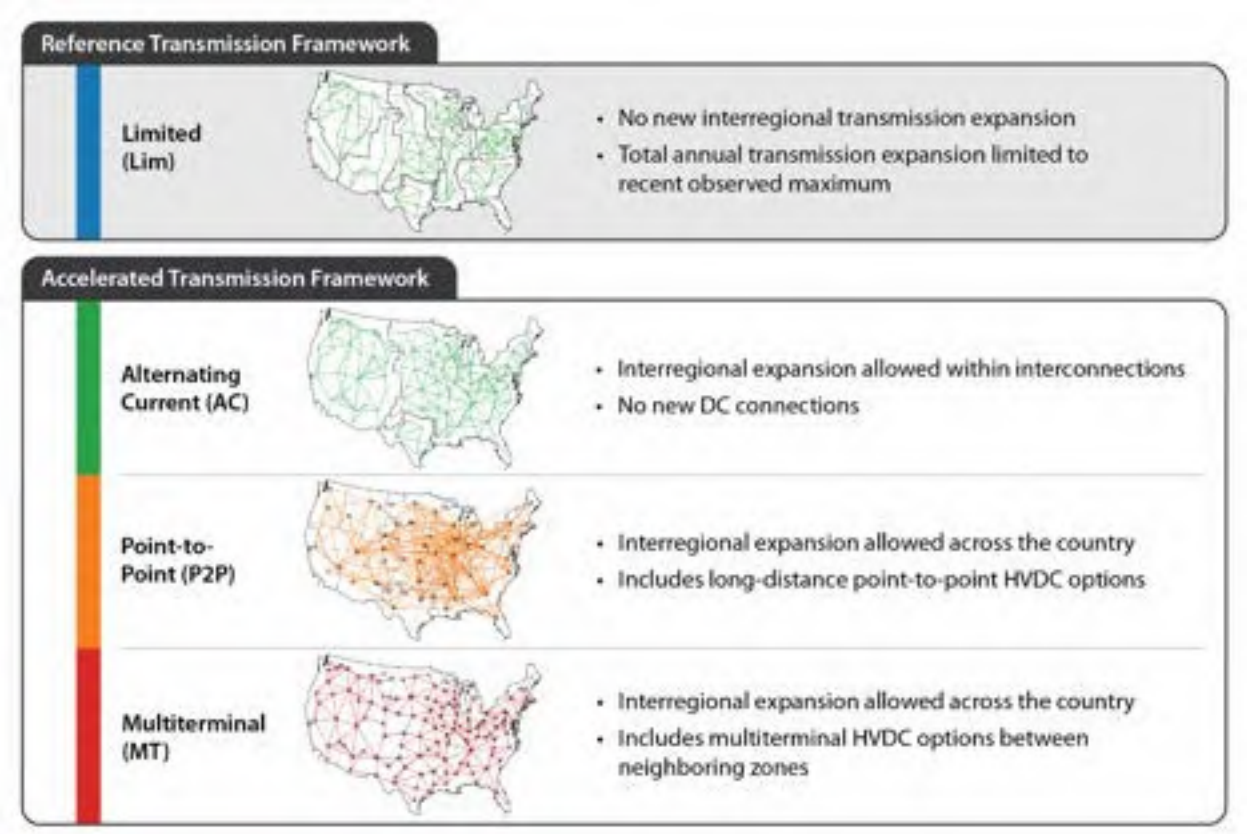


Figure I. NTP Study transmission frameworks

The scenario analysis first compares the different transmission frameworks without any new policies. Benefits from large-scale transmission expansion include billions of metric tons of avoided $CO_2$ emissions under current policies. Specifically, expanding transmission beyond historical rates—as occurs in the accelerated (AC, MT, P2P) frameworks—reduces power system $CO_2$ emissions by 10–11 billion metric tons (43%–48%) through 2050, relative to the Limited framework using "Mid" demand growth

assumptions (2.0%/year). The emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment. Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth.

The transmission frameworks were then evaluated considering nine decarbonization and demand futures (Figure II). Under these decarbonization conditions, benefits of large-scale transmission expansion include hundreds of billions of dollars in system cost savings. Specifically, in the central decarbonization scenarios—which achieve 90% emissions reductions by 2035 (100% by 2045) and assume Mid demand growth—accelerated transmission expansion leads to national electricity system cost savings through 2050 of $270–$490 billion. Constraining transmission growth results in more nuclear generation, hydrogen, and carbon capture capacity to achieve emissions reduction targets, leading to higher costs. The cost savings from accelerated transmission reveal that the costs of new transmission are outweighed by reductions in capital, operating, and fuel expenditures for generation and storage. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission in the AC, P2P, and MT transmission frameworks under our central decarbonization assumptions.

Figure II. Core demand and emissions assumptions.

*The central demand and emissions assumption is highlighted in yellow.*

The study finds rapid and significant growth in new transmission occurs in scenarios that achieve deep emissions reductions. Specifically, in the central decarbonization scenarios, the contiguous U.S. transmission system expands to 2.4–3.5 times the size of the 2020 system by 2050. This transmission occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country to enable increased access to wind and solar. Leveraging high-voltage direct current (HVDC) technologies, including advanced multiterminal converters, results in the greatest benefits. HVDC network solutions will require additional strengthening of AC networks. Similarly, the largest benefits of transmission are realized when interregional transmission is most substantial, including building across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions

exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6–4.6 times the 2020 capacity by 2050.

The analysis includes scenarios with faster rates of decarbonization (100% by 2035) and higher demand growth (2.7%/year) than assumed in the central scenario. These scenarios find that electrification drives greater deployment of transmission and generation capacity. The benefits of transmission expansion scale with the level of electricity demand and rate of decarbonization. Under "High" demand growth, estimated savings from accelerated transmission expansion range from $710 billion to $970 billion, and coupling High demand with more rapid decarbonization can yield more than $1 trillion in electricity system cost savings.

Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear are unavailable. The economic net benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many cases.

All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed current industry resource adequacy standards. A variety of technologies supports resource adequacy. Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability. In scenarios that allow coordination, transmission flows bidirectionally across many regional interfaces to support resource adequacy. With coordination, system costs through 2050 are lowered by $170 billion to $380 billion. Significant amounts of interregional transmission are built primarily to serve resource adequacy needs.

Lastly, the many scenarios and sensitivity cases in this chapter are also used to inform High Opportunity Transmission (HOT) interfaces that offer a starting point for further study. Spatial patterns in transmission expansion are similar across many sensitivity cases, and the HOT interfaces are defined as transmission expansion through 2035 between subregions that occurs in 75% of the sensitivity cases. Transmission projects that align with these HOT interfaces could be starting points for the grid expansion envisioned in this study.

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# 1 Introduction

The transmission grid has always played a critical role in the highly interconnected U.S. power system by delivering electricity from generators to load centers and supporting overall system reliability. As the U.S. generation mix undergoes major changes driven by clean energy policies and ambitions for deep decarbonization, the role of transmission is changing. Looking forward, how transmission might evolve to meet transformative generation changes while maintaining reliability is an open question. This chapter presents an analysis designed to answer this question for the contiguous U.S. electricity system.

Recent national decarbonization studies have collectively demonstrated the significant changes required in the U.S. transmission system to dramatically lower national greenhouse gas emissions. These studies include Denholm et al. (2022), the Net Zero America study (Larson et al. 2021), the Solar Futures Study (DOE 2021), Brown and Botterud (2021), and the North American Renewable Integration Study (Brinkman et al. 2021). Chapter 1 of this report and the Transmission Needs Study (DOE 2023a) summarize this body of work.

In addition to national-scale studies, regional planners also regularly conduct studies to examine future transmission expansion needs. These studies can lead to transmission expansion in utility or system plans and, ultimately, transmission procurement. Examples include California's long-term transmission plan (CAISO 2023a) and the Midcontinent Independent System Operator (MISO) Long Range Transmission Planning initiative (MISO 2022). Interregional transmission planning is more limited, but recent examples such as the MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (SPP and MISO 2022) and the U.S. Department of Energy (DOE) Atlantic Offshore Wind Transmission Study (Brinkman et al. 2024) demonstrate interest in broader multiregional planning efforts.

The analysis presented in this chapter is motivated by the growing awareness of transmission expansion needs and applies a scenario approach like many of the above-referenced national-scale studies. However, this chapter focuses on transmission using a scenario framework, described in Section 2, designed to isolate the impacts of transmission on the U.S. electricity system. The scenario analysis presented in this chapter uses long-term capacity expansion and resource adequacy (RA) modeling to provide insights into the following questions:

- What is the role of transmission in decarbonizing the U.S. energy system?
- What are the economic trade-offs between different transmission futures and corresponding resource mixes?
- What mechanisms help ensure future low-carbon grids are resource adequate, and how does transmission support these mechanisms?
- Which interregional transmission expansions are commonly developed across a range of scenarios?

The focus of the National Transmission Planning Study (NTP Study) on identifying transmission that will provide broad-scale benefits to electricity customers and inform interregional and national strategies to accelerate decarbonization while maintaining system reliability includes examining transformative changes to the entire portfolio and considering a full suite of generation, storage, and transmission options. The capacity expansion modeling used here enables such evaluations and the examination of a range of future conditions, of which there are several important uncertainties—especially for achieving a zero-emissions grid. Incorporating RA tools in the analysis helps develop plausible resource mixes that can be more thoroughly examined for reliability. The scenarios presented in this chapter serve as the starting points for the more detailed power system modeling presented in subsequent chapters to begin to examine other aspects of reliability.

Section 2 describes the grid models used and the scenario design and assumptions, and the appendices provide additional explanation and detail. Results are presented in Section 3, with each subsection presenting a different group of scenarios. Section 3.1 presents results from scenarios that include enacted policies only. Section 3.2 examines how results change under different emissions targets and demand assumptions but uses default assumptions for other model parameters. Section 3.3 focuses on scenarios under central decarbonization assumptions and includes results across the full set of sensitivity cases. Conclusions are discussed in Section 4.

# 2 Methodology

Two National Renewable Energy Laboratory (NREL) models, the Regional Energy Deployment System (ReEDS)[2] and Probabilistic Resource Adequacy Suite (PRAS),[3] are used for the capacity expansion and RA analysis presented in this chapter. Both open-source models operate with zonal resolution covering the contiguous United States as their geographic scope (Figure 1a). This section briefly describes these two models and additional approaches used for the scenario analysis presented in this chapter.[4]

## 2.1 Model Descriptions

**Regional Energy Deployment System (ReEDS).** The ReEDS model is used to create future power system scenarios. ReEDS chooses from a large set of new generation, storage, and transmission options to identify the systemwide least-cost portfolio that meets future demand, grid reliability, and policy requirements. For this study, the model finds the optimal resource mix in 5-year steps between 2020 and 2050. The model applies a centralized planning approach but subdivides the contiguous United States into 134 zones to represent the grid network and to reflect region-specific generation, demand, and policies. For investment and dispatch modeling, each solve year includes 33 representative days with 4-hour resolution from weather year 2012 (P. R. Brown, Cole, and Mai forthcoming). The ReEDS documentation (Ho et al. forthcoming) and 2023 Standard Scenarios report (Gagnon et al. 2024) describe the model in greater detail. Appendix A details newer features of ReEDS used for this study.

**Probabilistic Resource Adequacy Suite (PRAS).** The PRAS model assesses the resource adequacy[5] of the scenarios generated by ReEDS. PRAS measures adequacy by performing Monte Carlo analysis of thermal generator outages[6] and hourly dispatch over 7 weather years (2007–2013) of renewable energy availability. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This study uses the normalized expected unserved energy (NEUE)—EUE divided by total annual load—for the contiguous United States as the principal resource adequacy metric. PRAS has the same geographic scope and 134-zone resolution as ReEDS; however, thermal generator capacity within each zone is further subdivided into individual representative units to appropriately simulate generator outages.

[2] https://www.nrel.gov/analysis/reeds/
[3] https://www.nrel.gov/analysis/pras.html
[4] This chapter presents the methods, assumptions, and findings associated with the “round 2” scenarios of the NTP Study. Chapter 1 describes the primary differences between this round 2 capacity expansion analysis and the earlier round 1 analysis.
[5] The North American Electric Reliability Corporation (NERC) defines resource adequacy as “[t]he ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components” (NERC 2022).
[6] Transmission outages are not modeled; however, interregional transfer capacity assumed in PRAS and ReEDS partially accounts for transmission contingencies. See Appendix A for further detail.

**Integrated ReEDS-PRAS modeling.** The optimal resource mix identified by ReEDS accounts for RA by including up to 30 “stress periods” in addition to the 33 representative days. The stress periods are the days with the highest EUE, among 7 weather years, as estimated by PRAS. The stress periods can change over time or between scenarios; for example, with increasing electrification, stress periods can include winter days with high heating demand as well as hot summer days with air conditioning demand. ReEDS iteratively augments the portfolio to meet a user-specified reliability target. This study uses a national RA target of 10 parts per million (ppm) NEUE. Although NEUE-based system planning has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). Appendix B provides further detail on the combined use of ReEDS and PRAS.

**Other models.** Multiple upstream models are used to develop key inputs for ReEDS. The Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016) simulates the customer adoption of rooftop photovoltaic (PV) systems. Distributed PV projections from dGen are exogenously input to ReEDS. The Renewable Energy Potential (reV) model (Lopez et al. 2024) provides the wind and solar resource potential used in ReEDS as well as the hourly renewable generation profiles used by all the models. Additional key datasets are described in Appendix A.

**Transmission value analysis.** This chapter’s findings include results from an economic analysis of the scenarios, which assesses the relative costs between scenarios, the sources of those cost differences, and regional differences in costs and savings. This transmission value analysis primarily relies on a disaggregation of all the expenditures tracked in ReEDS—including generation, storage, and transmission capital and operating costs—through 2050 with additional adjustments to appropriately assess regional cost distributions.

## 2.2 Region and Transmission Terminology

The zonal ReEDS modeling represents the contiguous U.S. grid using 134 zones as shown in Figure 1a. These zones serve as the building blocks for larger regions for reporting purposes and to reflect policies and other factors. The zones conform to boundaries for the 48 states within the contiguous United States, which enables the representation of state clean energy policies.[7] This study focuses on 11 transmission “planning regions” that approximate Federal Energy Regulatory Commission (FERC) Order No. 1000 regions[8] and the Electric Reliability Council of Texas (ERCOT). The planning regions comprise aggregate model zones as shown in Figure 1c. These planning regions include the seven independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States. The 11 planning regions are

[7] The District of Columbia (D.C.) is combined with the zone that represents Maryland.
[8] The South Carolina Regional Transmission Planning (SCRTP) region from FERC Order No. 1000 is included in the Southeastern Regional Transmission Planning (SERTP) in the analysis. Nonenrolled members of FERC planning regions and regions that are not part of FERC Order No. 1000 are *included* within the geographic boundaries shown in the figure.

fundamental to the scenario design (as discussed next). Because there is significant variation in geographic size between the 11 planning regions, the larger planning regions are further subdivided into “planning subregions” (Figure 1b).[9] Results are typically reported at the planning region and subregion levels and for the contiguous United States as a whole. Figure 1d also shows the three asynchronous interconnections in the contiguous United States.[10]

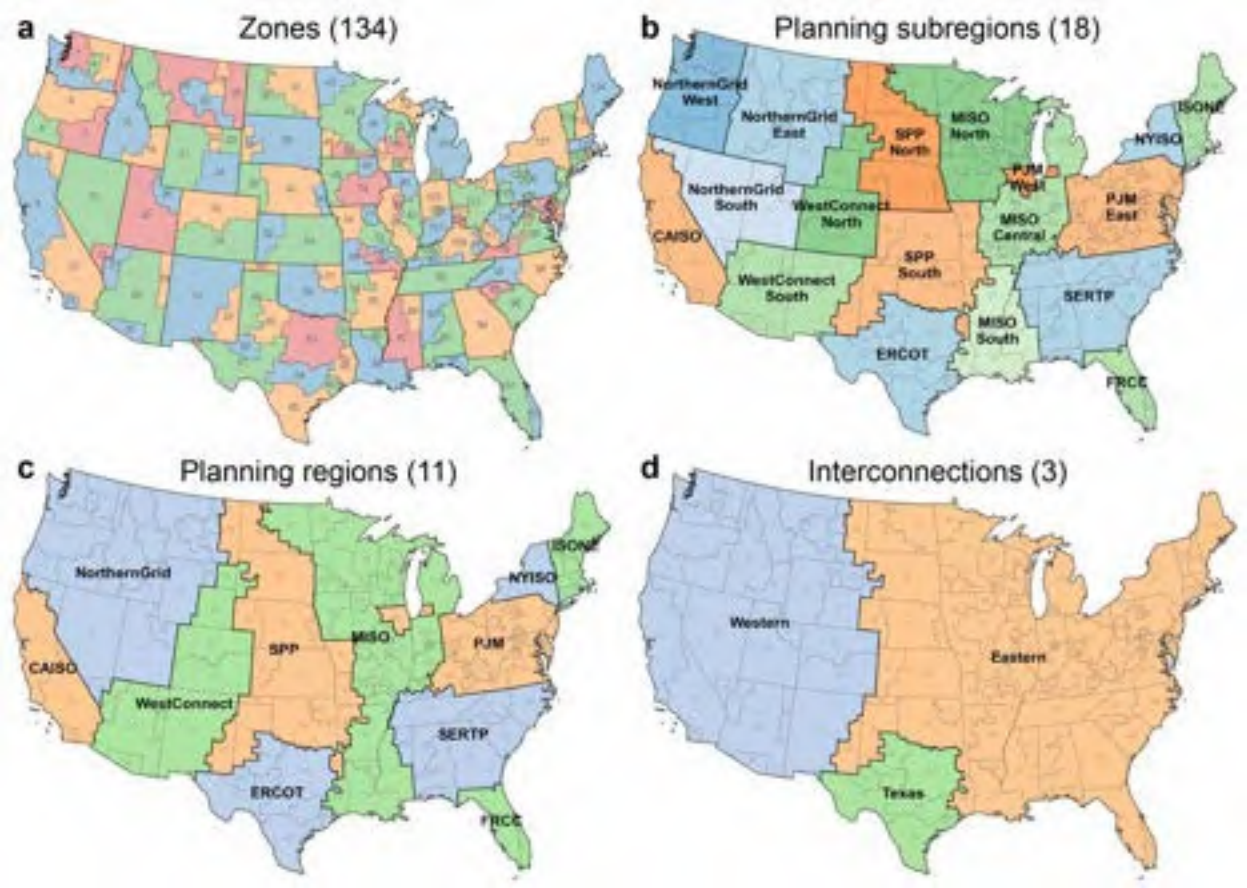



Figure 1. Hierarchy of regions used in the ReEDS model

*Regional acronyms: California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Independent System Operator of New England (ISONE), Southeastern Regional Transmission Planning (SERTP), Florida Reliability Coordinating Council (FRCC).*

The geographic regions include Tribal lands within the boundaries shown in Figure 1. The modeling does not specifically exclude or encourage new transmission or generation projects on Tribal lands, but the study team recognizes that energy planning

[9] There are 18 total planning “subregions” in the contiguous United States. NorthernGrid and MISO are both subdivided into three subregions each. WestConnect, SPP, and PJM are subdivided into two subregions each.

[10] The Western and Eastern interconnections also include electrically connected regions in Canada and Mexico. Given the focus on the contiguous U.S. system, international imports and exports are exogenously specified in the modeling. The North American Renewable Integration Study (NARIS) (Brinkman et al. 2021) evaluated cross-border transmission expansion.

on such locations would require engagement, consultation, and participation from the relevant Tribes. Chapter 1 highlights Tribal engagement during the NTP Study.

Different categories and types of transmission, which are partly defined based on the regions, are modeled and reported:

- **Local** transmission refers to estimated transmission expansion *within* each of the 134 model zones. It includes transmission spur lines from wind and solar power plants to a point of interconnection (POI) and network upgrades or reinforcements needed beyond the POI to interconnect these plants to the grid. Local transmission capacity is modeled and tracked only for land-based wind, offshore wind, solar PV, and concentrating solar power (CSP). The costs to interconnect other resources are assumed to be $100/kilowatt (kW) (approximating recent interconnection costs for gas turbines (Seel et al. 2023)) whereas interconnection costs for wind and solar vary widely by location and can be several hundreds of dollars per kW (Lopez et al. 2024).[11]
- **Interzonal** transmission refers to the transfer capacity between any pair of zones from the 134 model zones. Unlike local transmission, interzonal transmission is not specific to any resource but instead serves systemwide needs. Existing transfer capacity between model zones is estimated based on a method summarized in Appendix A and presented by Brown et al. (2023). Expansion of interzonal transmission is a model decision because ReEDS co-optimizes generation, storage, and transmission simultaneously. Interzonal transmission can be based on high-voltage alternating current (AC) or direct current (DC) technology assumptions as specified in the scenarios. DC technology options modeled include back-to-back (B2B) ties across interconnections, line-commutated converters (LCC), and voltage source converters (VSC). In this report, interzonal transmission is presented by transmission technology (AC, B2B, LCC, VSC) or further subdivided as follows:
    - **Regional** transmission refers to interzonal transmission between zones within the same planning region.
    - **Interregional** transmission refers to the transfer capacity between two different planning regions.
    - **Seam-crossing** transmission refers to the subset of interregional transmission that crosses interconnection boundaries.

Unless otherwise noted, “transmission” capacity reported includes all types of transmission, including local and interzonal transmission, and is typically measured in terawatt-miles (TW-miles) to account for both the capacity and the distances of all transmission. *Interregional* transmission capacity is typically reported in gigawatts (GW) or terawatts (TW) to measure the transfer capacity across regional interfaces irrespective of the lengths of the transmission lines that cross these boundaries.

[11] Real 2022 dollars are used unless otherwise noted.

Transmission cost assumptions for local and interzonal transmission of various types are described in Appendix A.

## 2.3 Scenario Design

The scenario framework includes 96 scenarios modeled using the ReEDS and PRAS models.[12] These scenarios span a range of demand, policy, and technology conditions to assess the varied role and extent of transmission in the future U.S. energy system. The 36 "core" scenarios are all combinations of four transmission frameworks (Figure 2), three demand growth projections, and three levels of power sector emissions constraints (Figure 3). The remaining 60 scenarios studied include 15 different sensitivity cases, each modeled for the four transmission frameworks under the central demand growth and emissions constraint assumptions. No judgment is made about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

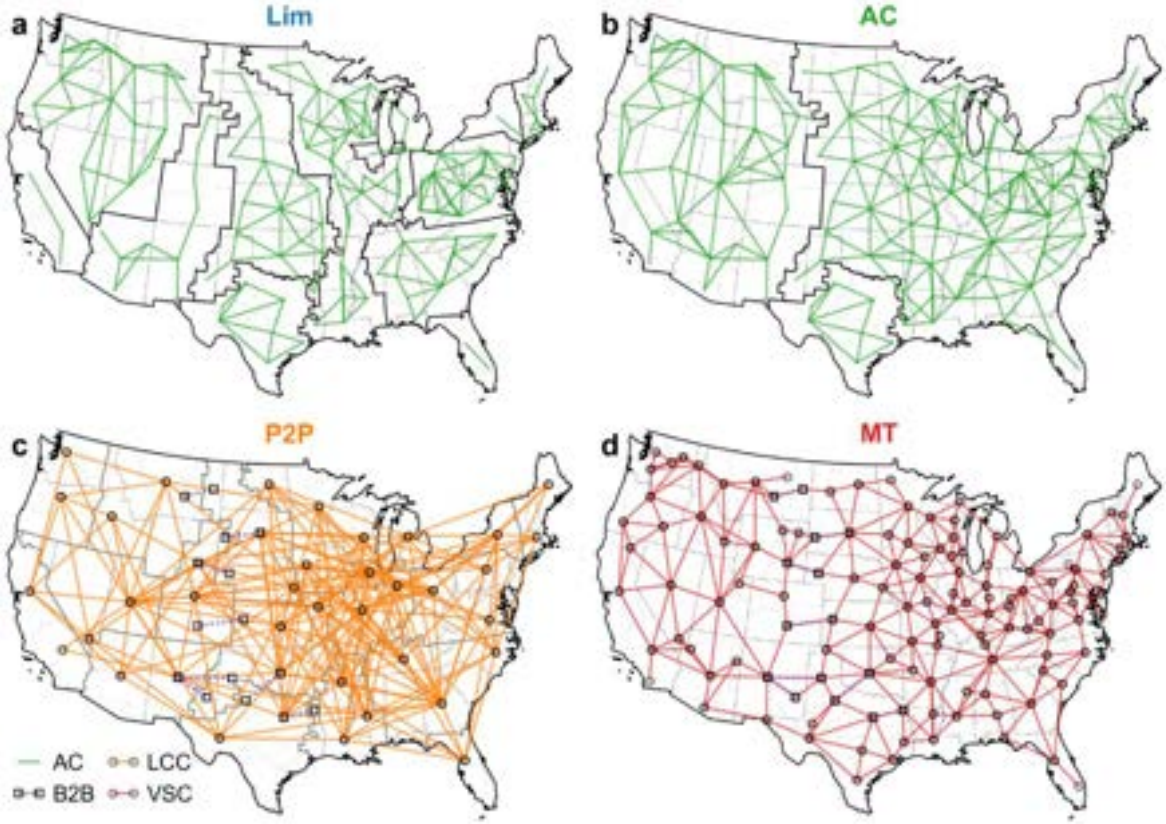



Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

*Maps show interfaces where transmission capacity can be expanded under the corresponding transmission framework. AC interfaces in the AC framework are also allowed to be expanded in the point-to-point (P2P) and multiterminal (MT) frameworks but are not shown for clarity. Existing transmission interfaces are not shown. Allowable transmission types are AC (green), high-voltage direct current (HVDC) with line-commutated converters (LCC, orange), HVDC with voltage source converters (VSC, red), and back-to-back interties (B2B, purple dashed).*

[12] Additional scenarios beyond these 96 are also modeled to address particular aspects as noted in the results.

Figure 3. Core demand and emissions assumptions

*The central demand and emissions assumption is highlighted in yellow.*

### 2.3.1 Transmission frameworks

The primary comparisons are between transmission frameworks (Figure 2), which enable the impacts of transmission on the overall evolution of the U.S. power system to be isolated. The four transmission frameworks differ by the types of constraints on and options for new transmission expansions. Differences in the constraints on transmission expansion represent factors other than cost that can affect transmission capacity growth (e.g. siting and permitting, interregional coordination). These transmission frameworks span a wide range of possibilities, from a "Limited" framework with severe constraints on new expansion to highly coordinated planning frameworks that incorporate the latest high-voltage direct current (HVDC) technology options.

- **Limited (Lim):** The Limited framework serves as the reference or counterfactual to the other transmission frameworks. In this framework, no new *interregional* transmission is allowed, reflecting a lack of coordination between planning regions or other barriers that prevent expansions of interregional transfer capacities.[13] Within each planning region, *regional* transmission expansion is allowed but is assumed to use AC technology. The exception is for existing HVDC connections, which are allowed to expand using new DC lines. In addition to excluding new interregional transmission, an annual limit on new transmission expansion is also applied in this framework, based on the maximum annual transmission builds since 2014 (Wiser et al. 2023). Using fixed carrying capacity assumptions for different voltages (see Appendix A), this limit is 1.83 TW-miles/year and is applied to total transmission—of all types—installed nationally across the contiguous United States. Because this limit applies to local as well as regional transmission expansion, it creates a de facto constraint on the growth rate for new wind and solar.
- **Alternating Current (AC):** The AC framework does not include an annual limit to the amount of transmission expansion. It also allows for interregional transmission expansion except for seam-crossing transmission. All interzonal transmission is assumed to use AC technology and associated costs and losses

[13] This framework may be more restrictive than current practices given interregional transmission planning processes already underway.

except for existing HVDC connections, where DC expansion is allowed. Transmission cost assumptions are presented in Appendix A.

- **Point-to-Point (P2P):** The P2P framework allows for the same expansions as in the AC framework but also allows new HVDC opportunities. These include B2B DC ties across interconnections and 195 candidate P2P connections, including those between nonadjacent regions. These P2P candidates, shown in Figure 2, are identified based on locations with the highest wind resource and/or demand in each planning subregion. Only connections within 1,000 miles are considered. For these P2P candidates, HVDC line costs, which are lower than AC line costs,[14] and converter costs are based on LCC technologies.[15] Converters and lines are required to be identically sized.
- **Multiterminal (MT):** The MT framework allows for the same expansions as the AC framework but also includes options for HVDC expansion between adjacent zones. HVDC line costs are assumed to be the same as those for the P2P framework, but converter costs are slightly higher and based on VSC technology. However, unlike the P2P framework, converters and lines are independently sized by ReEDS in the MT framework. This approach enables more flexibility for a meshed network design, but this framework does not allow the 195 long-distance candidates from the P2P framework.[16]

The analysis primarily compares results from the AC, P2P, and MT frameworks, which are referred to as *accelerated* transmission frameworks because the rate of transmission expansions can exceed recent maximum annual builds, to the Limited framework. Both the P2P and MT frameworks extend the transmission options allowed in the AC framework by emphasizing HVDC technologies but represent distinct HVDC network designs.

### 2.3.2 Policy assumptions and emissions targets

How the role of transmission might change depending on decarbonization levels is a key question of the analysis. The baseline level of grid decarbonization is affected by enacted policies, which are included in all 96 scenarios.[17] These electric sector policies include state laws and federal clean energy tax incentives. State policies modeled include 28 renewable portfolio standards (RPSs)[18] and 15 clean energy standards. The assumptions for these factors are based on data from Barbose et al. (2023) and from stakeholder feedback received during the study. Technology-specific requirements from state RPS policies are also modeled, including offshore wind targets. The assumed mandated offshore wind deployment targets are based on analysis from DOE's

[14] HVDC line losses are also lower than AC losses, but additional losses are modeled for the AC-to-DC-to-AC conversions.
[15] Converter costs under the P2P and MT frameworks differ based on the assumed technologies used (LCC and VSC, respectively); however, the modeling is not prescriptive about which technology might be best suited.
[16] Connections between two nonadjacent zones would require multiple separate segments under the MT framework whereas P2P might have a direct connection with a shorter distance and lower costs.
[17] Existing policies as of June 2023 are modeled.
[18] Hawaii is not modeled. Washington, D.C. also has an RPS, and this policy is considered within the zone that includes both Maryland and D.C.

Offshore Wind Market Report: 2023 edition (Musial et al. 2023).[19] Electric sector greenhouse gas (GHG) emissions policies for the Regional Greenhouse Gas Initiative states and California are also included. State retirement policies for existing plants and bans for new nuclear or fossil capacity are also included (Gagnon et al. 2024). County and other local siting ordinances, tracked from Lopez et al. (2023), for new wind and solar development are also modeled as part of the wind and solar resource potential inputs to the model (Lopez et al. 2024).

Federal policies modeled include many of the clean energy tax incentive provisions from the Inflation Reduction Act (IRA) of 2022 and the Bipartisan Infrastructure Law of 2021.[20] The IRA tax incentives include production and investment tax credits for new wind, solar, other renewable energy, energy storage, and carbon capture and storage (CCS).[21] Steinberg et al. (2023) document the assumptions used to represent these policies in ReEDS. The tax credit level and period when the IRA incentives are available vary by technology. The wind, solar, and storage tax credits expire depending on the annual U.S. power sector emissions; the IRA specifies these credits expire when annual emissions are below 25% of 2022 levels or in 2032, whichever is later. For some scenarios, the IRA tax credits phase out as written, and for others the wind, solar, and storage tax credits are assumed to expire in 2032 to facilitate the comparison of scenarios without confounding changes in tax policy conditions.

In addition to the enacted policies, decarbonization scenarios are modeled using national emissions constraints (Figure 3). The following three power sector emissions trajectories are used in the scenarios:

- **Current policies:** Current policies include enacted state and federal policies as of June 2023 as described previously. No other policies, such as a national constraint on emissions, are included.
- **90% by 2035:** In addition to enacted policies, a national annual limit on power sector carbon dioxide equivalent ($CO_2$(e)) emissions is applied in the 90% by 2035 scenarios.[22] This limit is set to achieve 90% reductions from 2005 levels by

[19] These assumptions result in 47 GW of prescribed offshore wind capacity by the mid-2030s, all of which are off the Atlantic coast except for 4.7 GW of offshore wind by 2035 in the Pacific based on the Base case from the California Public Utilities Commission (2022).
[20] Only major legislation and mandates are included in the modeling. Nonbinding and voluntary targets from states, corporations, or utilities are not included. The modeling is not comprehensive of all policies, especially those applied at the local level. The assumptions also represent a snapshot in time of the policy environment, which can change rapidly.
[21] Tax credits for hydrogen technologies are not included in this analysis because guidance for these tax incentives was not released at the time this analysis was completed. Clean Air Act section 111 standards are not included because they were also not finalized when this analysis was completed.
[22] The limit applies to direct $CO_2$ emissions from fossil-fuel-fired power plants as well as from upstream $CO_2$(e) methane emissions. The modeling assumes a 100-year global warming potential of 34 to estimate the $CO_2$(e) of methane and assume a leakage rate of 2.3% in 2021 (Alvarez et al. 2018), declining by 30% to 1.6% in 2030 and thereafter (Denholm et al. 2022).

2035 and 100% reductions by 2045.[23] The limit declines linearly from 2025 to 2035, declines linearly between 2035 and 2045, and stays at 0 million metric tons (MMT) $CO_2$ after 2045. Figure 4 shows the emissions trajectory used in these scenarios along with historical emissions for context. This trajectory is used under the central decarbonization assumptions.

- **100% by 2035:** The emissions limit in the 100% by 2035 scenario is applied similarly to the 90% by 2035 scenario, except the trajectory achieves zero emissions by 2035 and stays at that level through 2050 (Figure 4). The 2035 zero emissions limit is consistent with the U.S. carbon-free electricity by 2035 target (Executive Office of the President 2021).

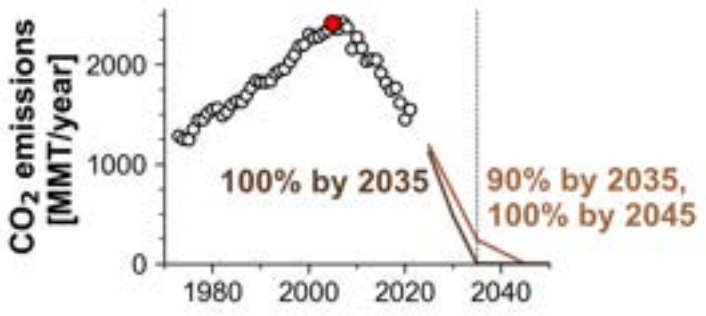



Figure 4. Emissions constraints under grid decarbonization scenarios

*Historical emissions are from EIA (2024b). Power sector emissions in 2005 are 2,411 MMT $CO_2$.*

### 2.3.3 Electricity demand growth assumptions

Historical and future load growth are impacted by macroeconomic factors, energy efficiency, and electrification or potential new sources of demand (e.g., growth in data centers). To account for significant uncertainties with these factors, three demand scenarios spanning a wide range of growth possibilities are modeled (Figure 5). The compound annual growth rate for demand in these scenarios varies from 0.9%/year to 2.7%/year (2021 to 2050) and is largely correlated with the rate of electrification and corresponding reductions in direct emissions from end-use sectors such as transportation, buildings, and industry.[24] For context, U.S. load grew by 1.1%/year during the prior 30 years (1992 to 2021) but experienced much flatter growth during the past 15 years (0.1%/year) and higher growth (2.8%/year) over the longer (1962–2021) period. The three demand trajectories are based on demand-side modeling from Evolved Energy Research and calibrated using 2021 state-level demand data from EIA (2021):

- **Low-Demand:** The Low-Demand trajectory is from the "Baseline" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022), which largely follows

[23] Noncaptured $CO_2$ from fossil with CCS plants count against these emissions limits; however, these emissions can be offset by bioenergy with CCS (BECCS) options or other negative emissions technologies when allowed. Direct air capture (DAC) is not included in the core scenarios but is included in a sensitivity. Emissions from fossil plants without CCS are not allowed to be offset in the definition used here.

[24] Appendix A shows the estimated end-use emissions by sector in the three demand cases.

EIA's Annual Energy Outlook (AEO) 2022 Reference case (EIA 2022). It does not include electric vehicle tax credits and other electrification or clean energy tax incentives from the IRA. Annual demand grows by 0.9%/year from 2021 to 2050 under Low-Demand.

- **Mid-Demand:** The Mid-Demand trajectory is more representative of enacted policies because it includes the electrification incentives for various end-use sectors from the IRA. This case features "moderate" electrification assumptions as used in Haley et al. (2023).[25] Load growth is 2.0%/year. This trajectory is used as the central decarbonization assumption.
- **High-Demand:** The High-Demand trajectory includes substantial electrification consistent with achieving net zero energy emissions by 2050. This assumption is from the "Central" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022). Because of high electrification, demand grows by 2.7%/year, resulting in 2050 annual demand that approximately doubles national demand from 2021.

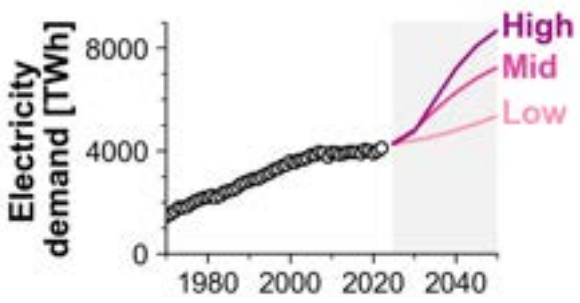



Figure 5. Annual demand assumptions for the contiguous United States

*Historical demand shown is electricity sales to ultimate customers from EIA (2024b).*

Hourly demand profiles also change over time and vary across the Low-, Mid-, and High-Demand trajectories. Electrification of buildings under Mid- and High-Demand results in winter demand peaks that grow faster than summer peaks in many regions. Figure 6 shows these changes in the demand profile over time for the contiguous United States, but the shifts toward winter peaks are even starker in colder regions. Demand data used in the models are at hourly resolution for each state; all zones within a state share the same normalized load profile, but state annual demand is partitioned based on historical distributions of load.

[25] Specifically, the "Current Policy" scenario from Haley et al. (2023) is used for the Mid-Demand case.

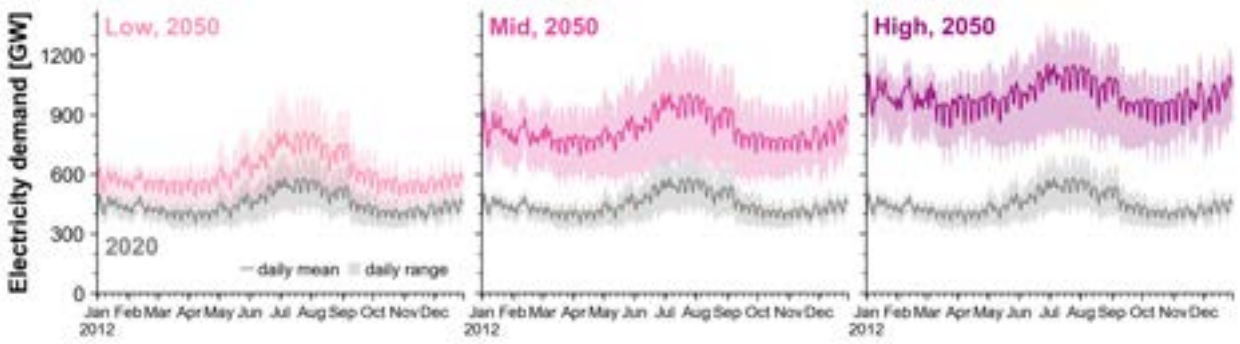



Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

*The demand profiles shown use 2012 weather.*

### 2.3.4 Other default assumptions

Aside from the differences in transmission framework, power sector emissions target, and demand outlined previously, all other assumptions are the same across the 36 core scenarios. These default assumptions include technology cost and performance assumptions from the NREL Annual Technology Baseline (ATB) 2023 Moderate case (National Renewable Energy Laboratory 2023) (see Appendix C) and fuel costs from the EIA AEO 2023 Reference case (EIA 2023a). Distributed rooftop PV adoption is also held constant between scenarios and is assumed to reach 130 $GW_{AC}$ by 2035 and 170 $GW_{AC}$ by 2050 (Gagnon et al. 2024), compared with 48 $GW_{AC}$ of small scale PV in 2023 (EIA 2024a).

For $CO_2$ transport and storage costs, a uniform $15/metric ton cost for all regions is applied, without limits on the amount of $CO_2$ that could be injected.[26] Hydrogen storage is modeled explicitly to ensure sufficient storage capacity for the daily balancing of $H_2$ production, storage, and use.[27] However, all hydrogen must be used in the same zone in which it is produced; transport of $H_2$ between zones is not allowed in any scenario. Further work is needed to compare trade-offs between electricity transmission and transport of other energy carriers. Appendix A details the hydrogen representation used for this study.

Unless otherwise noted, all other assumptions are from the NREL Standard Scenarios 2023 Mid-case (Gagnon et al. 2024).

### 2.3.5 Sensitivity cases

In addition to the core scenarios, 15 sensitivity cases are modeled under all four transmission frameworks. These 60 sensitivity cases all assume 90% by 2035 power sector emissions trajectory and Mid-Demand growth—which represent the central decarbonization conditions. Table 1 summarizes the sensitivity cases.

[26] Brown et al. (forthcoming) presents the endogenous model representation for $CO_2$ transport and storage. A test scenario using this capability resulted in similar findings to those presented here. Scenarios with greater CCS deployment could have different implications.
[27] No hydrogen demand for industry, transportation, or other uses outside for electricity generation are considered; all reported hydrogen production and use in the scenarios are for grid applications.

Table 1. Sensitivity Cases

| Name | Description |
|---|---|
| PV+Battery Low Cost | PV and battery technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023). |
| Wind Low Cost | Land-based and offshore wind technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023). |
| Electrolyzer Low Cost | Electrolyzer costs are based on DOE (2023b). Electrolyzer costs in the core scenarios decline linearly from $1,750/kW in 2022 to $550/kW in 2030 and stay constant thereafter; costs in this sensitivity case undergo further linear declines from $550/kW in 2030 to $157/kW in 2050. |
| +Nuclear SMR +DAC | Assumes nuclear small modular reactor (SMR) and direct air capture (DAC) technologies are commercially available. Nuclear SMR costs are from the ATB 2023 Moderate case (National Renewable Energy Laboratory 2023) and DAC costs are from Brown et al. (forthcoming). DAC can be used to offset emissions from fossil CCS plants. |
| No Interface Expansion Limit | In all other scenarios, a 30-GW limit is imposed for total interzonal capacity (combined existing and new, AC and DC). This sensitivity case eliminates this maximum level.[28] |
| Transmission 2x Cost | Interzonal $/megawatt-mile (MW-mile) transmission costs are doubled for all interfaces for both AC and DC capacity. Default transmission costs are presented in Appendix A. |
| No RA Sharing | Requires each of the 18 subregions to meet adequacy needs locally; no trades are allowed across subregion boundaries during the modeled stress periods. This represents a lack of interregional coordination for resource adequacy. (See Appendix A for details.) |
| Siting Limited | Uses more-constrained siting supply curves for land-based wind and utility PV, based on “Limited Access” from Lopez et al. (2024), as opposed to the default “Reference Access.” This reduces the technical potential from 11.1 TW to 5.9 TW for wind and from 112 TW to 58 TW for PV. Reductions are not uniform by region. |
| CTS High Cost | $CO_2$ transport and storage (CTS) costs are assumed to be $36/metric ton instead of $15/metric ton under default assumptions. These assumptions are based on Grant et al. (2019) as discussed in Brown et al. (forthcoming). |
| Many Challenges | Uses higher technology costs for PV, wind, battery, CCS, and nuclear technologies based on projections from the ATB 2023 Conservative case (National Renewable Energy Laboratory 2023). Uses the more-constrained supply curves for wind and utility PV as in the “Siting Limited” sensitivity. |
| No $H_2$ | Hydrogen electrolyzers and combustion turbines (CTs) are not available. |

[28] The 30-GW limit is based on iterations with the preliminary nodal modeling in the study that indicated expanding beyond this level would be technically challenging.

| Name | Description |
|---|---|
| No CCS | CCS technologies are not available. |
| No $H_2$ or CCS | Hydrogen and CCS technologies are not available. |
| No $H_2$ or New Nuclear | Hydrogen technologies and new nuclear deployment are not available. |
| Climate | Modifies demand, solar, and wind profiles to be based on future weather conditions developed from a global climate model and downscaled (Buster et al. 2023). Hydropower capacity during stress periods is assumed to be reduced by 20% in 2050. Summer capacities for thermal generators and transmission for 2050 are derated by 15% and 5%, respectively. Capacity derates ramp linearly from 0% in 2025 to these values. (See Appendix A for details.) |

## 2.4 Modeling and Analysis Limitations

The analysis examines the future role of transmission using sophisticated power sector tools; however, there are limitations of the analysis especially given the transformative and wide-ranging scenarios examined and the very large and complex nature of the U.S. electricity system. Here, several important limitations of the modeling in this chapter are discussed.

Behavioral, institutional, and regulatory aspects are not fully reflected in the models. The models apply a centralized economic optimization approach rather than the more-complex decision-making reality in today's energy system. Diverse decision makers can have different objectives and considerations that would lead to different planning and operational outcomes than those found by the models. Select sensitivity cases partially address interregional coordination and uncertainties with siting and permitting renewable energy projects. Additional analysis is needed to study these issues in greater depth and to quantify their impacts.

Energy planning for transmission and other electricity resources is complicated by the limited foresight of future policy, market, and technology conditions and the long-lived nature of these assets. These uncertainties are partially captured through the wide range of scenarios modeled; however, the capacity expansion modeling used here does not reflect the limited foresight conditions of reality. Specifically, ReEDS finds the optimal resource mix sequentially for each 5-year increment from 2020 to 2050 with no foresight on how policies, technologies, or fuel prices might change. This would give a suboptimal solution relative to an intertemporally optimized model that sees the full 30-year period altogether. On the other hand, ReEDS assumes the construction, permitting, and other planning and approval efforts are successfully executed prior to the modeled installation dates. This perfect "construction" foresight approach does not account for manufacturing, supply chain, and workforce needs that may impact the rate of technology deployment. The modeling does not directly reflect all these complexities—either inside or outside of the electricity sector—that may be required to realize these scenarios. Similarly, perfect foresight is assumed in the dispatch decisions from ReEDS and PRAS.

Comprehensively evaluating full economywide and broader societal cost and benefits of the scenarios is outside the scope of this analysis. The analysis compares differences in direct power system expenditures, nationally and by region, to evaluate the economic viability of transmission under a range of future conditions. This includes all expenditures for the bulk power system but does not include distribution system expenditures or an economic evaluation of the demand-side sectors under the various electrification futures modeled. Moreover, the cost, benefits, and impacts of GHG emissions levels or other air pollution are out of scope. Finally, distributional impacts to different demographic groups and stakeholders are also not evaluated in this analysis.

Although the analysis includes many scenarios, not all possibilities are analyzed. Importantly, the modeling does not explicitly include all technology options. For example, the cost assumptions for new transmission are based on estimates for greenfield projects; transmission upgrades or grid-enhancing technologies (GETs) that could yield expanded transfer capacity at potentially lower costs are not directly modeled in ReEDS. Some of the expanded transmission capacities reported can be realized through these other options. ReEDS modeling also includes diurnal and seasonal (hydrogen) energy storage (see Appendix A) but does not explicitly include other long-duration storage options. The scenarios also include increases in rooftop PV capacity, but other distributed energy resources, demand response, and demand-side flexibility options are not modeled.[29] The omission of demand flexibility—including managed electric vehicle charging—could be particularly important with respect to the RA results presented.

This chapter's analysis includes RA modeling but does not fully consider other elements of reliability, such as operational reliability and resilience. Resource adequacy is considered through the integrated ReEDS-PRAS modeling, which includes generator outages and variability, weather-driven variability, a wide range of long-term demand projections, and approximations for transmission contingencies through interregional capacity derates. However, generator fuel supply limits, correlated outages, and transmission outages are not modeled. Appendix B discusses these and other limitations of the RA analysis. Subsequent chapters supplement the analysis with other elements of reliability not considered by the capacity expansion models used in this chapter.

Further study is needed to examine these important aspects.

[29] Sensitivity cases with higher distributed PV levels were modeled in earlier stages of the study but had less impact on the scenario outcomes than many other sensitivity cases presented here.

# 3 Results

## 3.1 Current Policies

This section reports findings from scenarios assuming current policies (as of June 2023) only. Scenarios with additional constraints on national carbon emissions are presented in subsequent sections.

### 3.1.1 Benefits from large-scale transmission expansion include billions of metric tons of avoided $CO_2$ emissions

Accelerating transmission expansion beyond the historical rate specified in the Limited framework has a strong effect on electricity sector $CO_2$ emissions under current policies (Figure 7). Under mid demand, modeled electricity sector emissions in 2035 are roughly 810 MMT $CO_2$ per year in the Limited framework and 440–460 MMT/year in the three accelerated transmission frameworks (AC, P2P, MT), a 44%–45% reduction. Annual emissions reductions from accelerated transmission are even larger in 2050, roughly 56%–61%. On a cumulative (2025–2050) basis, the accelerated frameworks avoid 10.2–11.2 billion metric tons of $CO_2$ (43%–48%) relative to the Limited framework.

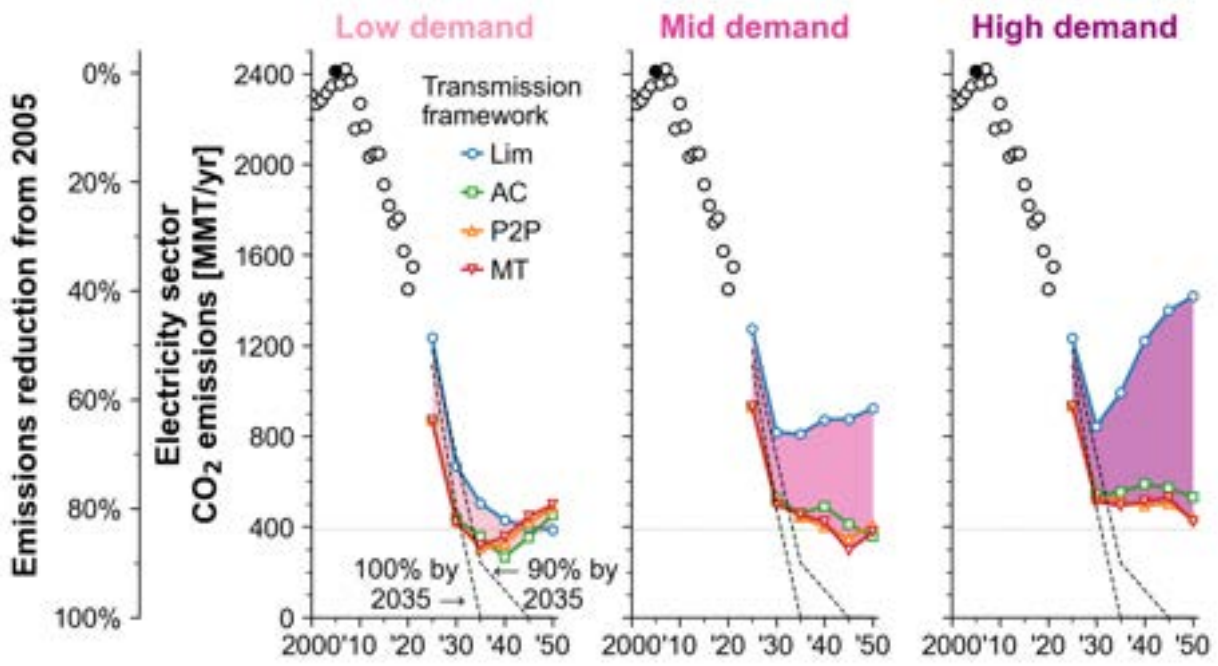



Figure 7. Electricity sector $CO_2$ emissions under current policies across demand assumptions

*The 90% by 2035/100% by 2045 and 100% by 2035 emissions trajectories are indicated by black dashed lines. The IRA tax credit phaseout threshold (75% $CO_2$ emissions reduction compared to 2022) is indicated by gray dotted lines. Historical emissions (black circles) are from EIA (EIA 2024b). The shaded area represents the change in emissions from the Limited transmission framework.*

Notably, even without new policies, each of the three accelerated transmission frameworks is on track for $CO_2$ emissions reductions on par with both the 90% by 2035 and 100% by 2035 emissions trajectories through 2030 (Figure 7). The Limited transmission framework, by contrast, reaches at most a 66% emissions reduction

relative to 2005. As discussed below, under current policies, emissions reductions stall or even reverse after 2030 as a result of the phaseout of the IRA tax credits (with low demand) or accelerated demand growth in the decades after 2030 (with mid or high demand).

Modeled emissions also depend strongly on the assumed demand growth. In the Limited transmission framework, 2050 $CO_2$ emissions with High-Demand are 3.7 times the emissions under Low-Demand (Figure 7a,c). The annual emissions reductions from accelerated transmission under high demand are 44%–50% in 2035 (440–500 MMT $CO_2$/year) and 62%–70% in 2050 (890–990 MMT $CO_2$/year), resulting in cumulative $CO_2$ savings of 14.3–15.7 billion metric tons (48%–52%). Conversely, cumulative $CO_2$ savings are more modest with Low-Demand (3.1–3.8 billion metric tons, or 21%–26%). This comparison applies only to electricity sector emissions; different demand trajectories have very different direct end-use emissions (Appendix A).

The emissions trends are complicated by the phaseout conditions for the IRA tax credits; as written, the credits start phasing out in 2032 or the year in which electricity sector emissions drop 75% below their 2022 level, whichever is later. The three accelerated transmission frameworks trigger the tax credit phaseout under Low-Demand growth, leading to increasing emissions between 2040 and 2050, whereas the Limited transmission framework never reaches 75% emissions reductions and thus never triggers the phaseout.

### *Emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment*

Wind and solar deployment are significantly accelerated in the AC, P2P, and MT transmission frameworks compared to the Limited framework (Figure 8) because the annual deployment limits on local interconnection capacity (required for new wind and solar) and long-distance transmission are removed. Under Mid-Demand Current Policies assumptions, wind capacity expands to 5.8 times its 2020 capacity by 2050 in the Limited framework and 8.6–8.8 times in the accelerated transmission frameworks; solar capacity expands 10 times in the Limited framework and 14–17 times in the accelerated transmission frameworks. In 2035, wind capacity is 34%–42% higher in the accelerated transmission frameworks than in the Limited framework; solar capacity is 32%–59% higher. The share of total 2050 generation from variable renewable energy (VRE)—wind and solar combined—expands to 55% in the Limited framework and 77%–79% in the three accelerated transmission frameworks.

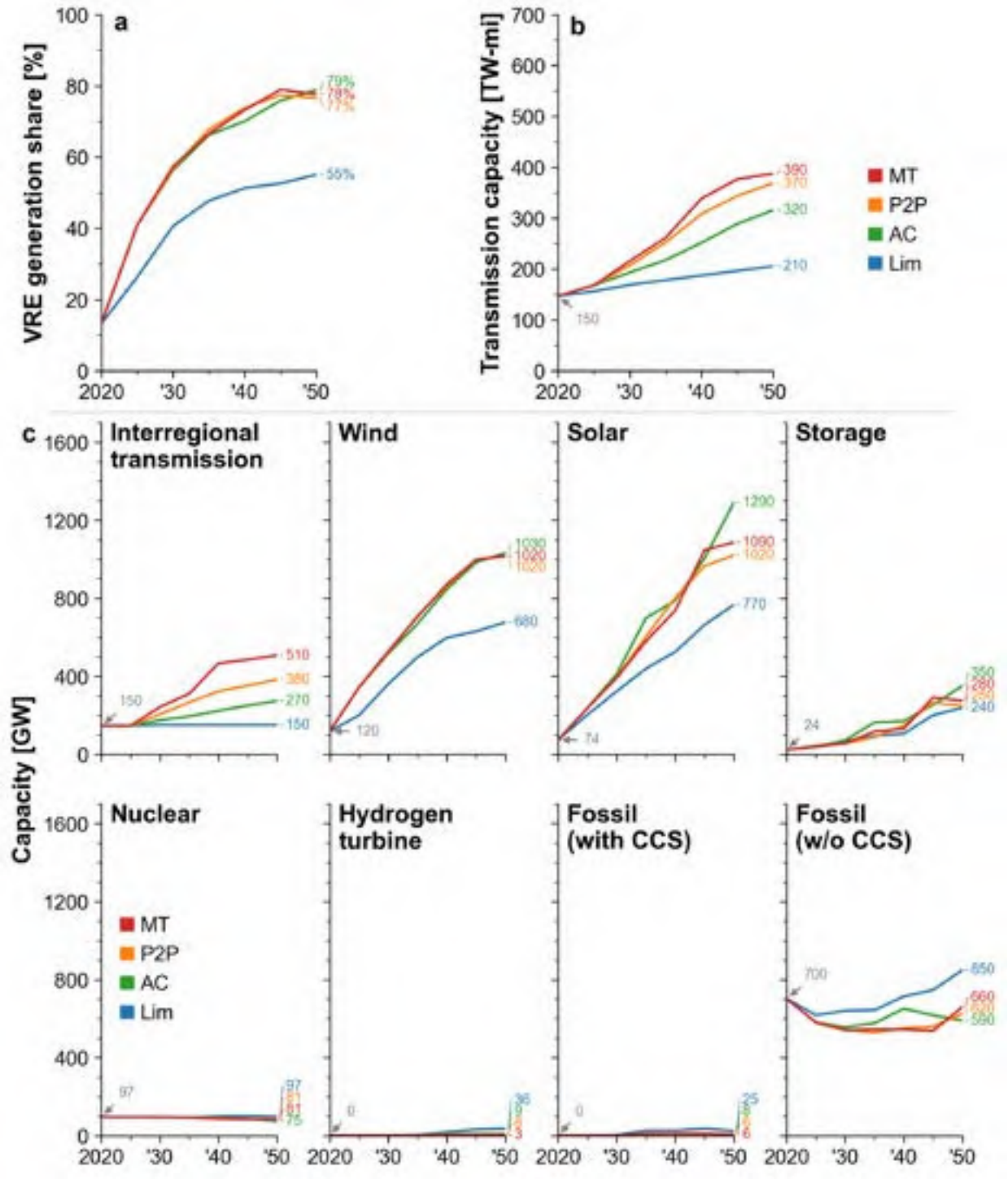



Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"Total" transmission capacity (Figure 8b), including both local interconnection capacity (spur lines and network reinforcement associated with new wind and solar additions) within the 134 ReEDS model zones and long-distance interzonal transmission capacity between the model zones, is reported in units of TW-miles. Compared to the estimated

2020 capacity of ~150 TW-miles, total transmission capacity in 2050 grows to 1.4 times in the Limited framework, 2.1 times in the AC framework, 2.5 times in the P2P framework, and 2.6 times in the MT framework. “Interregional” transmission (Figure 8c) is shown in GW and represents the total bidirectional transfer capability between the 11 planning regions (Figure 1c). Compared to the estimated 2020 transfer capacity of ~150 GW, interregional transmission capacity does not expand in the Limited framework (as required by the scenario design, discussed in Section 2.3.1) and grows to 1.9 times in AC, 2.6 times in P2P, and 3.5 times in MT.

***Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth***

Though modeled power sector emissions are in line with the 90% by 2035 and 100% by 2035 trajectories through 2030, they diverge over the subsequent two decades (Figure 7). Fossil capacity is higher in 2050 than in 2020 in the Limited framework because the total transmission deployment limit of ~1.83 TW-miles/year substantially constrains the deployment of competing wind and solar technologies. Even in the accelerated transmission frameworks, fossil capacity in the Mid-Demand scenarios never drops more than 25% below its 2020 capacity under current policies (Figure 8), and electricity sector $CO_2$ emissions never drop more than 81% below their 2022 level (Figure 7).

## 3.2 Demand Growth and Emissions Constraints

This section presents findings from the core scenarios (Figure 3), including those that span multiple demand growth trajectories and different constraints on national power sector emissions. Unless otherwise noted, in the following results the IRA tax credits are assumed to expire in 2032 to facilitate more direct comparisons using the same policy conditions.

### 3.2.1 Rapid and significant growth in new transmission capacity occurs in scenarios that achieve deep emissions reductions

Applying an emissions requirement significantly expands the deployment of transmission in frameworks that allow transmission expansion (Figure 9). Under Mid-Demand assumptions, 2050 transmission capacity is 37%–68% higher with a 90% by 2035 emissions requirement than with Current Policies for each of the three accelerated transmission expansion frameworks. The Limited transmission framework is bound by the 1.83 TW-miles/year deployment constraint in nearly all scenarios.[30] Because the 90% by 2035 and 100% by 2035 scenarios achieve 100% emissions reductions by 2045 at the latest, the 2050 transmission capacity does not change significantly between these scenarios when demand scenario and transmission framework are held constant. However, near-term transmission deployment is accelerated in the 100% by 2035 scenarios: 2035 transmission capacity is 15%–34% higher in the 100% by 2035 scenarios than in the 90% by 2035 scenarios for the three accelerated transmission frameworks.

[30] With low demand and current policies, the annual transmission growth constraint of the Limited framework is not reached.

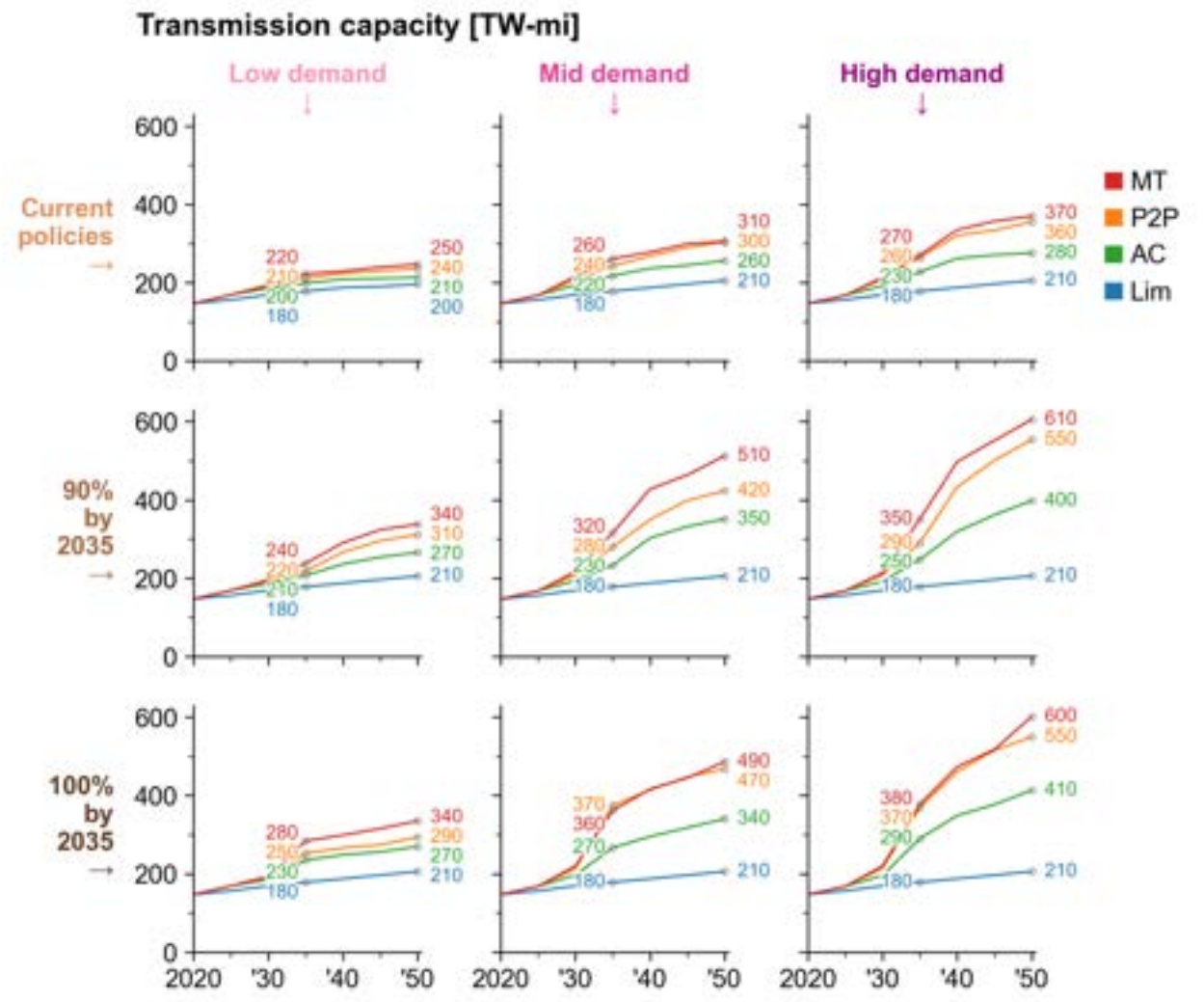



Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

*Total transmission capacity includes local interconnection capacity (spur lines and network reinforcement) within the 134 ReEDS zones and long-distance interzonal transmission capacity between ReEDS zones. For this plot, the IRA tax credit is assumed to begin phasing out in 2032 for all scenarios (including for current policies), irrespective of emissions, to facilitate comparison across scenarios while keeping policy assumptions constant.*

For context, Figure 10 shows the average transmission growth rate between 2025 and 2050 compared to different benchmarks for historical transmission deployment. In the central Mid-Demand 90% by 2035 scenario, annual transmission additions in the three accelerated transmission frameworks range from 2.0 to 3.8 times the maximum annual rate of transmission deployment observed in the United States since 2009. Alternatively, comparing the modeled rate of annual transmission deployment to individual HVDC links that have been built in the past in a collection of countries shows this rate of growth equates to the addition of 2.7–5.1 “Pacific-DC Intertie” links (built in the United States in 1970 and upgraded since) per year (Pierre et al. 2019), 0.8–1.5 “Rio Madeira” links (completed in Brazil in 2014) per year (Hitachi 2022), or one “Changji-Guquan” link (completed in China in 2019) every 1.8–3.3 years (Hitachi 2020).

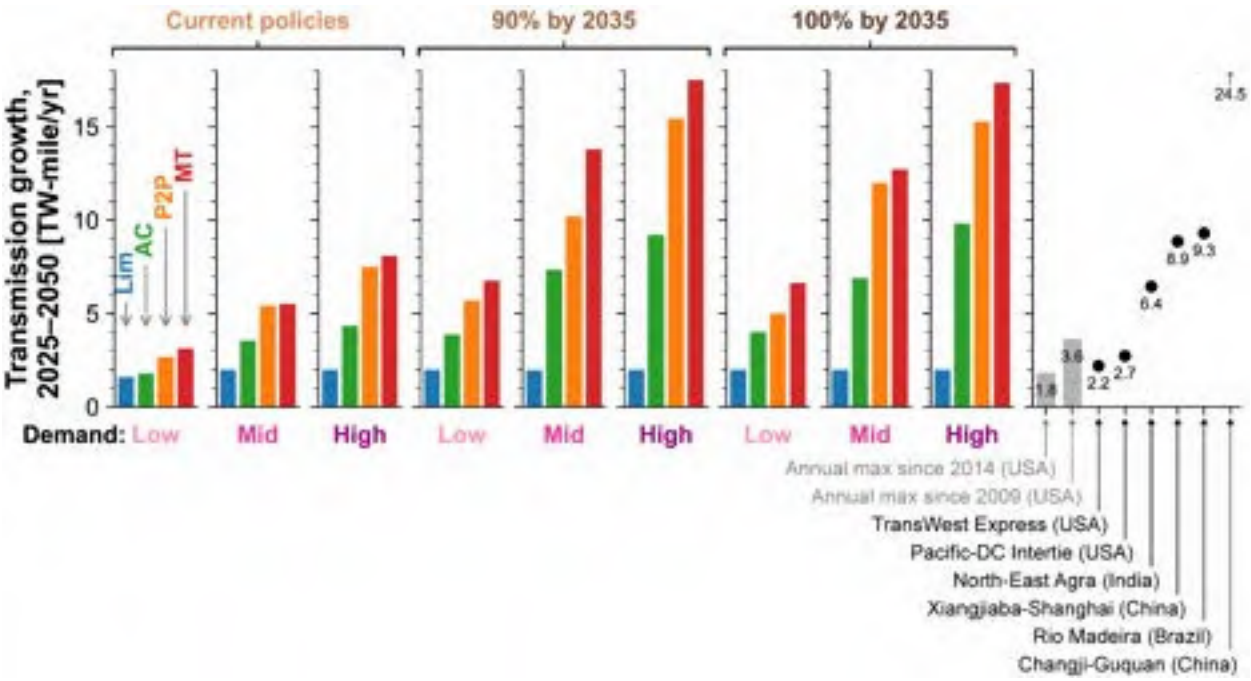



Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

*The gray bars for "Annual max since 2009" and "Annual max since 2014" refer to U.S. transmission additions as discussed in Wiser et al. (2023). The filled markers indicate individual historically constructed HVDC projects for scale (Pierre et al. 2019; TransWest Express 2024; Power Technology 2020; Hitachi 2020; 2022; 2024).*

### *Electrification drives greater deployment of transmission and generation capacity*

The assumed level of demand growth has a significant impact on total transmission deployment. Relative to 2020 transmission capacity, the 2050 transmission capacity in the three accelerated transmission scenarios grows from 1.5 to 1.7 times for low demand to 1.9–2.5 times for high demand under current policies (Figure 9). Combined with a decarbonization policy, the impact of demand growth is even stronger: With 90% by 2035 and 100% by 2035 emissions reductions, 2050 transmission capacity grows from 1.8 to 2.3 times its 2020 level for low demand to 2.7–4.1 times for high demand. Scenarios with high demand through electrification and that achieve 100% grid emissions reductions approximate net zero emissions for the U.S. energy system as a whole (Section 2.3.3).

As with total transmission capacity, demand growth and decarbonization policy are strong drivers of interregional transmission deployment (Figure 11). Interregional transmission capacity, which is defined as the capacity between the 11 planning regions in Figure 1c, grows to 1.5–2.7 times its 2020 capacity by 2035 in the three accelerated transmission frameworks in the Mid-Demand 90% by 2035 scenario and 1.6–3.3 times in the High-Demand 100% by 2035 scenario. By 2050, these ranges grow to 2.6–4.6 times in the Mid-Demand 90% by 2035 scenario and 2.6–5.3 times in the High-Demand 100% by 2035 scenario.

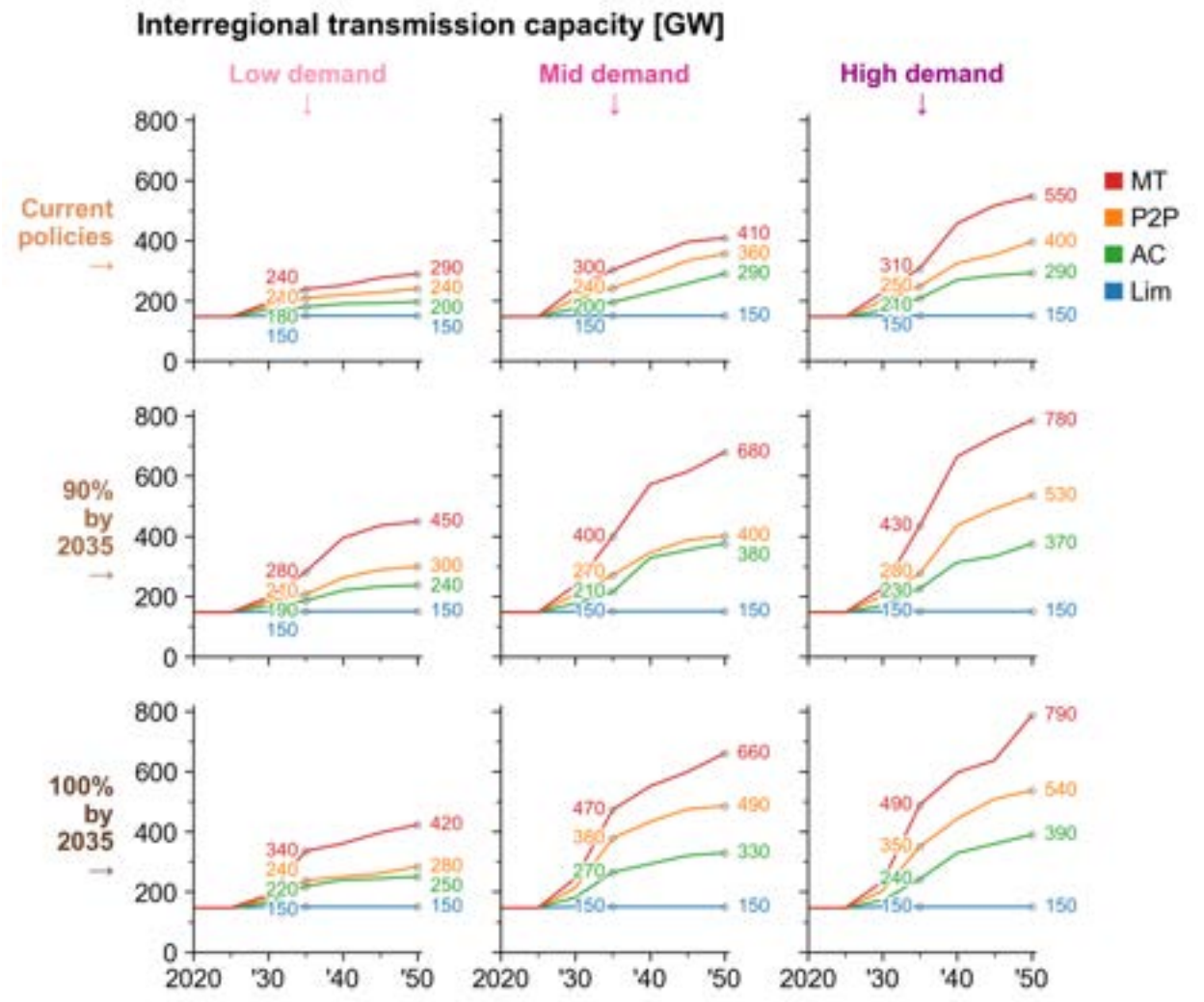



Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

*"Interregional" transmission capacity is measured between the 11 planning regions shown in Figure 1. For this plot, the IRA tax credit phaseout is assumed to begin in 2032 for all scenarios (including for current policies) to facilitate comparison across scenarios while keeping policy assumptions constant.*

Installed wind and solar capacity also scales with demand growth in the accelerated transmission frameworks (Figure 12). In the 90% by 2035 scenarios, 2050 wind capacity grows to 6–7 times its 2020 capacity with low demand, 9–10 times with mid demand, and 12–13 times with high demand; PV capacity grows to 13–14 times, 15 times, and 18–19 times, respectively. Nuclear capacity grows appreciably only in the Limited transmission framework with mid/high demand and either 90% by 2035 or 100% by 2035 emissions constraints, where it grows to ~2 times 2020 capacity under mid demand and ~4 times under high demand (compared to ≤3% growth in all other transmission frameworks and demand/emissions assumptions).

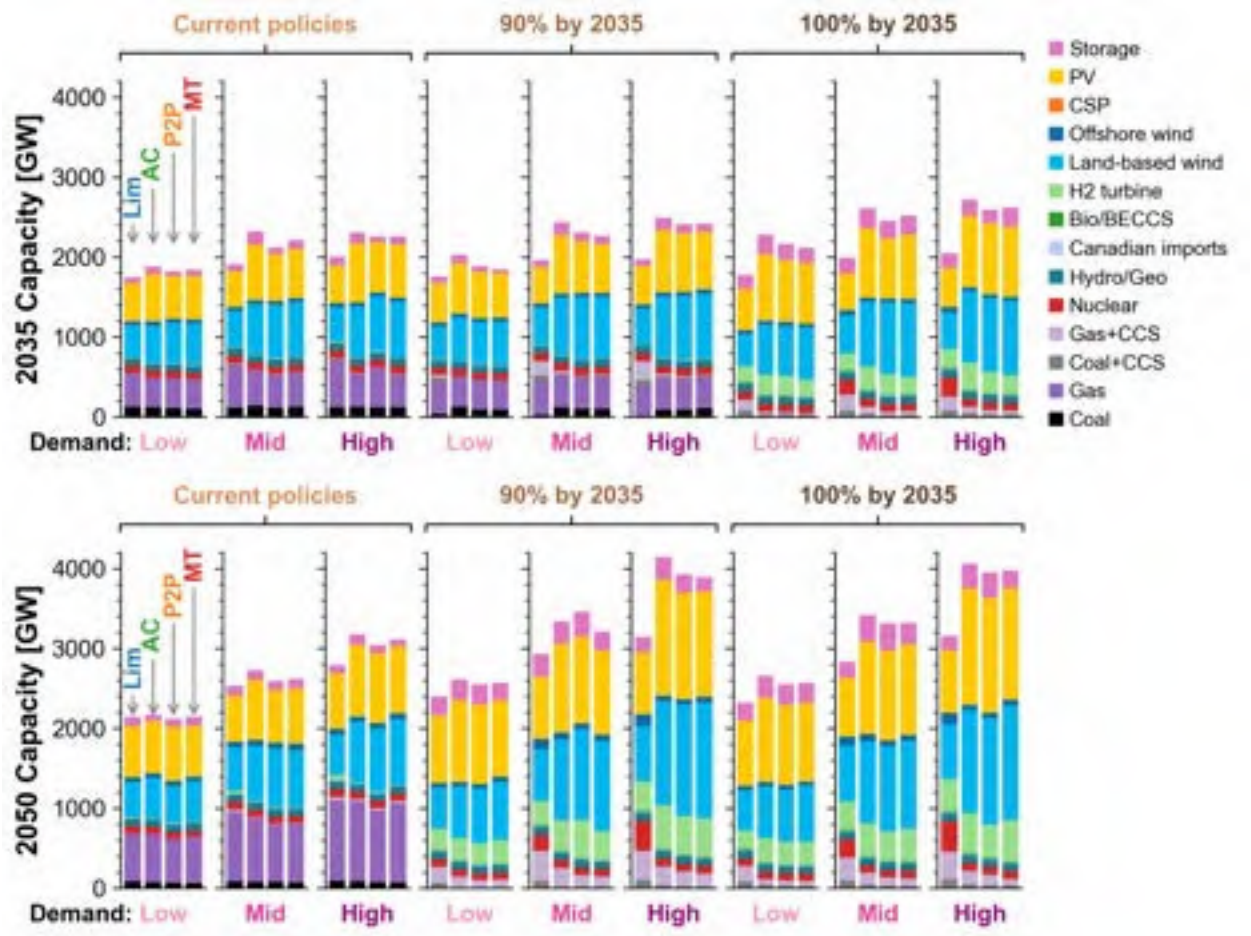



Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

### 3.2.2 Benefits from large-scale transmission expansion include hundreds of billions of dollars in system cost savings under decarbonization futures

Though accelerating transmission expansion leads to reductions in $CO_2$ emissions under current policies, with national emissions limits that fully eliminate grid emissions, the primary impact of accelerated transmission expansion is a reduction in electricity system costs. The main cost metric is the net present value (NPV) of total electricity system costs through 2050, including fixed and operating costs and tax incentives for electricity producers.[31] Figure 13 shows this metric across the 90% by 2035 and 100% by 2035 emissions assumptions (rows), three demand trajectories (columns), and four transmission frameworks (bars). Accelerating transmission expansion reduces costs by $270–490 billion under Mid-Demand/90% by 2035 assumptions, with the AC framework at the bottom of the range of savings and MT at the top (a 4%–8% reduction compared to the $6,370 billion NPV of system costs in the Limited framework).

[31] Unless otherwise noted, the NPV costs are for all expenditures from 2022 to 2050 using a 1.7% societal real discount rate (OMB 2023).

Savings from accelerated transmission increase when decarbonization is achieved more quickly (to $570–810 billion under Mid-Demand/100% by 2035 assumptions) and when demand growth increases (to $710–970 billion in High demand/90% by 2035 and to $860–1,220 billion in High demand/100% by 2035).

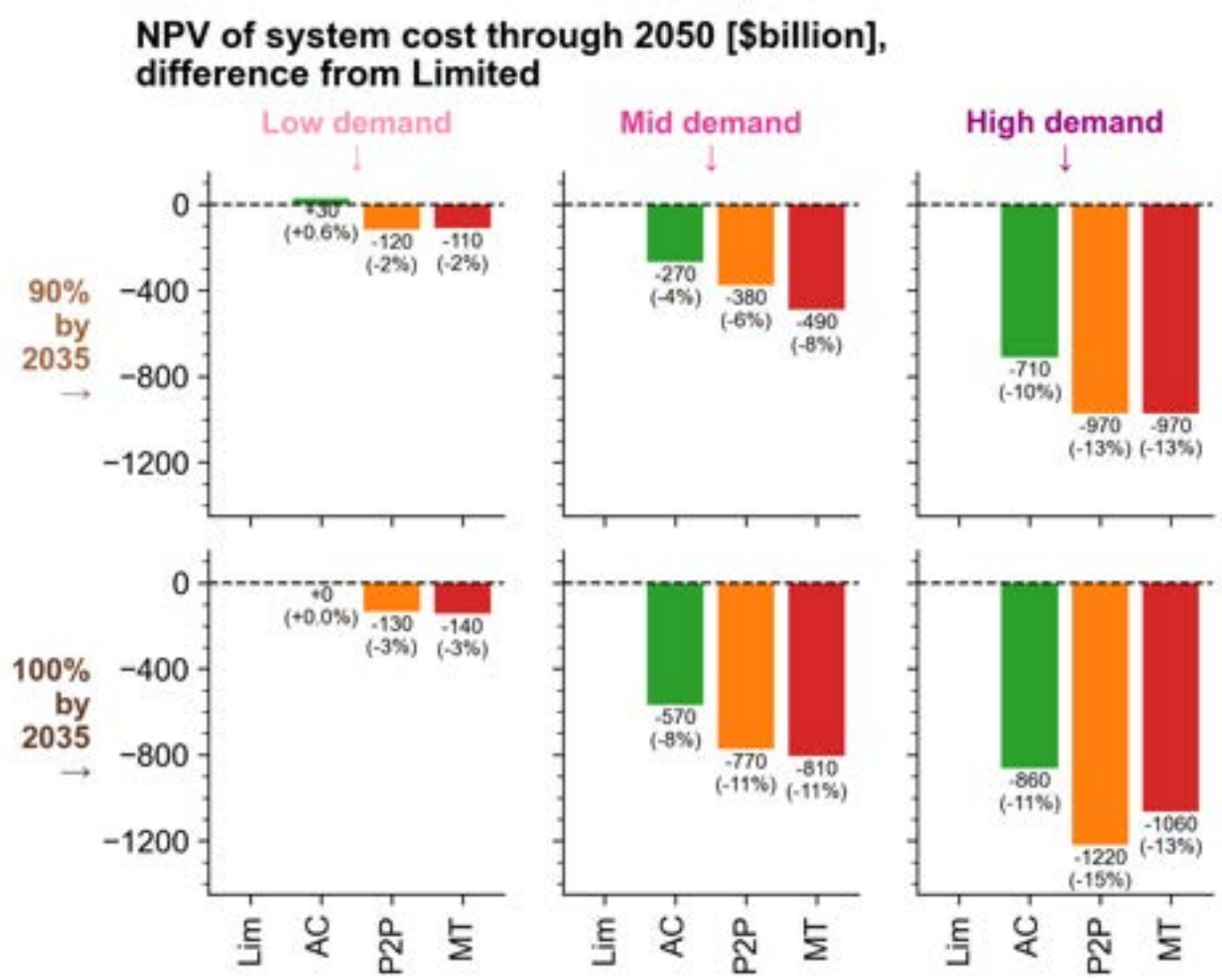



Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

*The cost change in each of the three accelerated transmission frameworks relative to the Limited framework is given in $billion and as a percent change below each bar. Differences below ~1% (~$50 billion) are considered within the model uncertainty bounds resulting from imperfect foresight and scenario-specific stress periods.*

## 3.3 Central Demand and Emissions Assumptions

Sections 3.1 and 3.2 show results across all core scenarios, which cover a range of emissions reductions and demand growth assumptions. This section presents findings from the central demand and emissions constraint scenarios, which assume Mid-Demand growth trajectories and 90% emissions reductions by 2035 (100% by 2045). These central scenarios include both the core and the 15 sensitivity cases (Table 1).

### 3.3.1 Accelerating transmission deployment consistently reduces system cost across a spectrum of sensitivity cases

Across all modeled sensitivity cases, the system cost of a given case is uniformly lower in the three accelerated transmission frameworks than in the Limited transmission framework (Figure 14, Figure 15, and Figure 16), and transmission expansion consistently delivers hundreds of billions of dollars of savings. The core scenario savings of $270–490 billion are on the low end of the modeled sensitivity cases (Figure 16): The range of savings across all sensitivity cases is $270–760 billion for the AC framework; $380–1,170 billion for P2P; and $350–1,170 billion for MT.

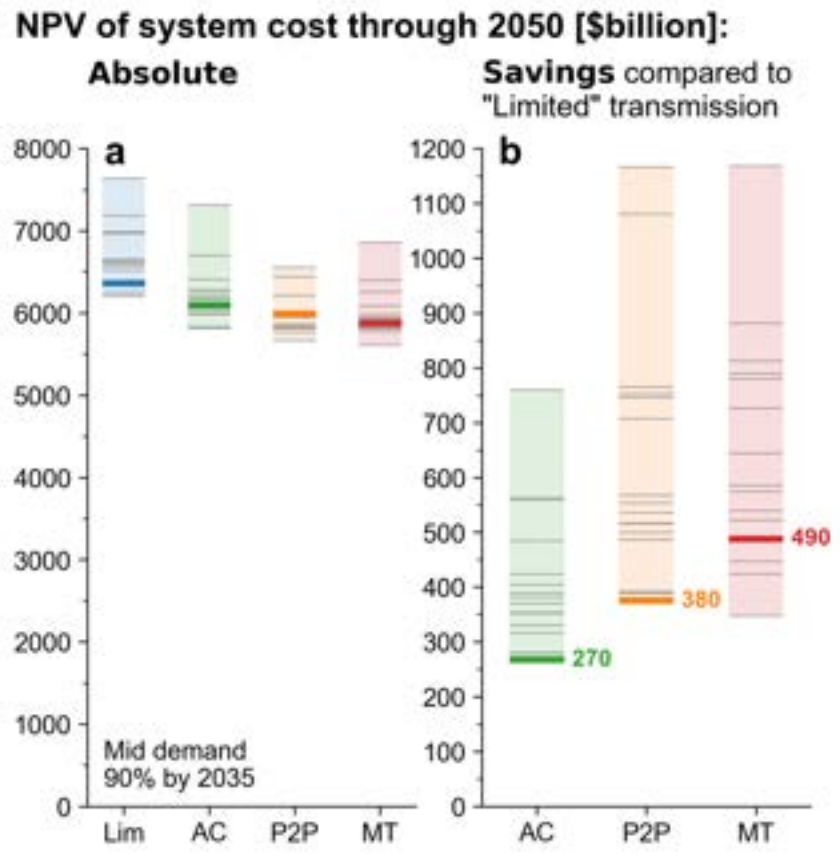



Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

*Note the change in y-axis scale between panels (a) and (b). Bold line indicates the core scenario result.*

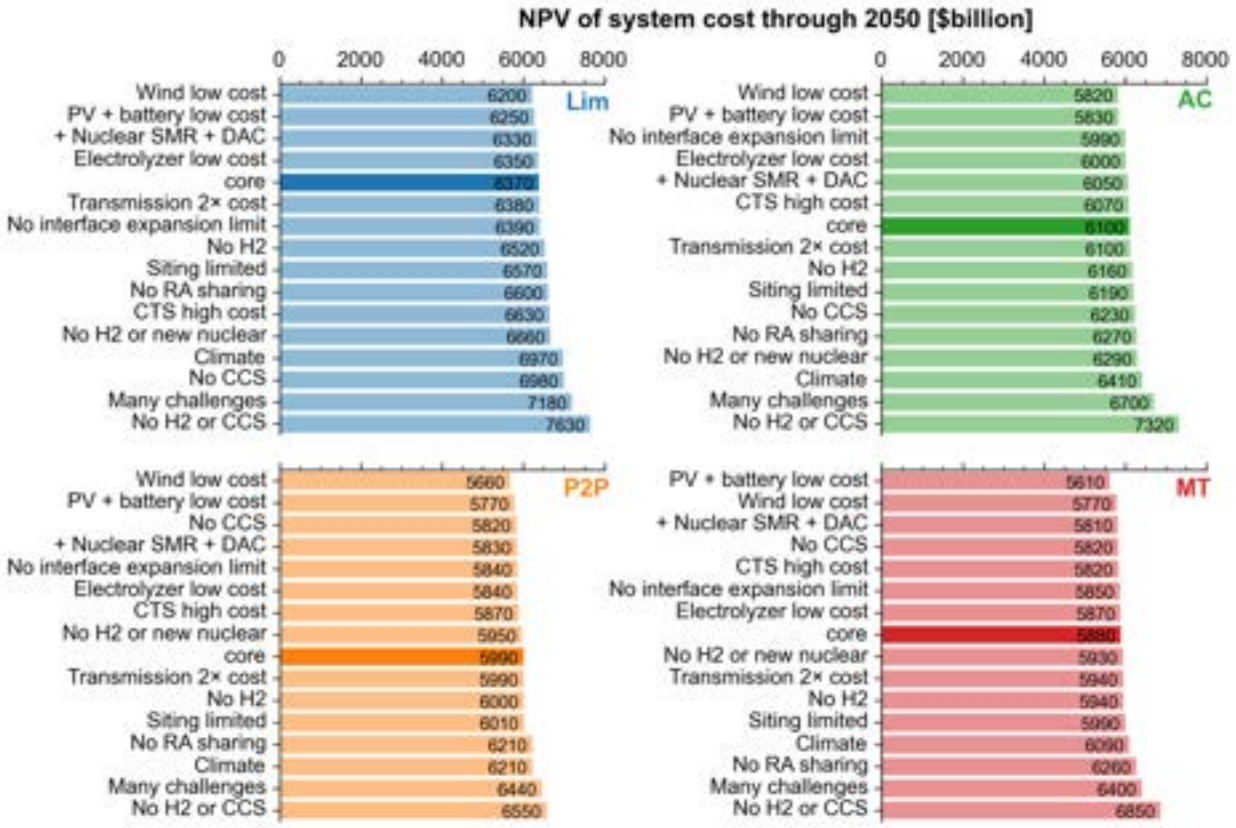



Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

*The savings in each of the three accelerated transmission frameworks relative to the Limited framework are given as numbers in billions of dollars at the right of each bar. Scenarios within each transmission framework are sorted by absolute system cost.*

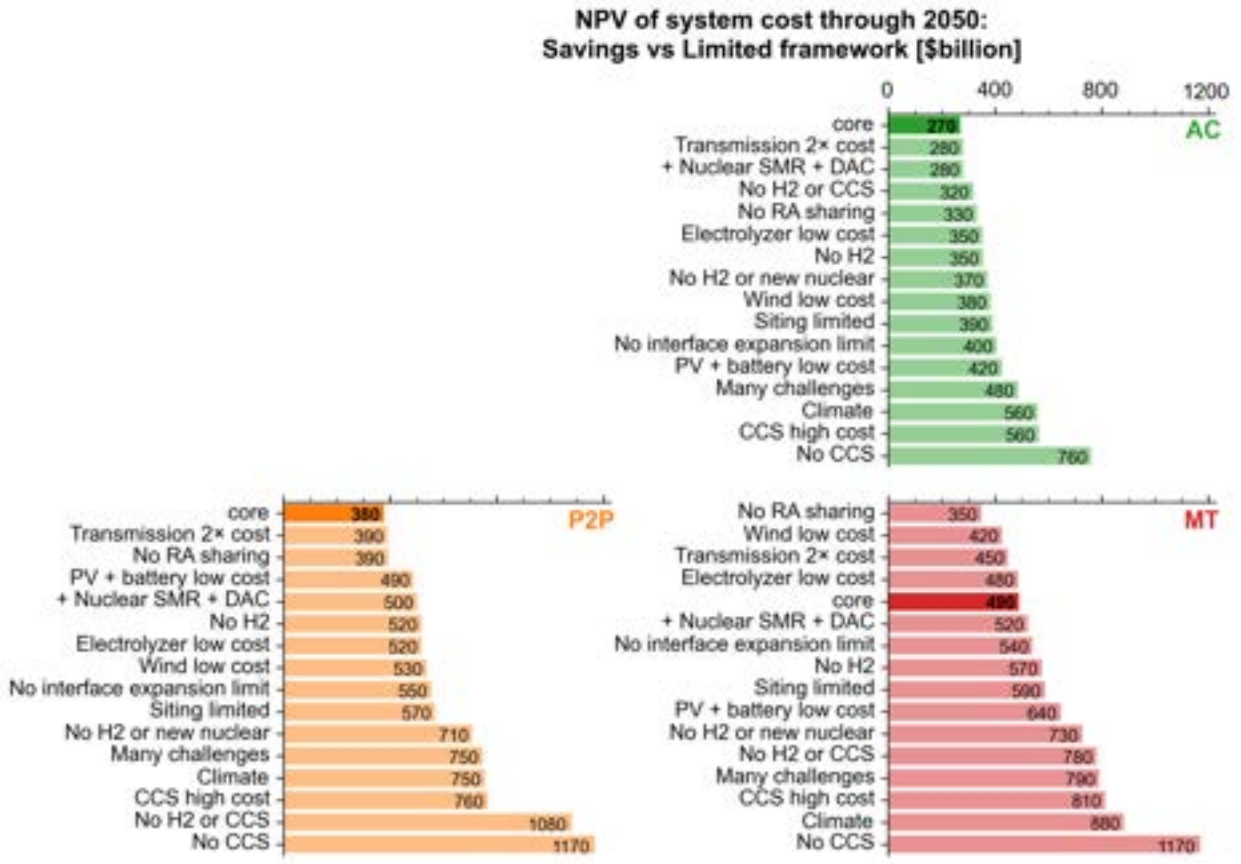



Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

*Scenarios within each transmission framework are sorted by system cost savings relative to the Limited framework.*

Savings from accelerated transmission are largest in futures where alternative technologies are constrained or more expensive. The highest savings from accelerated transmission are in the "No CCS" sensitivity case: Without CCS, costs rise by ~$600 billion in the Limited framework but are relatively unaffected in the other frameworks, leading to savings of ~$800–1,200 billion from accelerated transmission when CCS is unavailable. Transmission-induced savings also increase in the "No $H_2$" and "No $H_2$ or new nuclear" sensitivity cases. Transmission expansion could help hedge against the possibility that new low-carbon technologies face difficulties in scaling up from their currently low annual deployment rates. Conversely, if these low-carbon generation technologies become commercially available—as assumed under the core scenarios—the benefits of accelerated transmission expansion are lower but still substantial as discussed previously. Savings from accelerated transmission expansion are also $100–190 billion higher in the "Siting limited" case than in the core scenario, $220–370 billion higher in the "Many challenges" case, and $290–390 billion higher in the "Climate" case. Notably, cost savings from accelerated transmission expansion under the "Transmission 2× cost" case ($280–450 billion) are similar to savings under the core scenario.

### *Lower system costs in the accelerated transmission frameworks significantly outweigh the costs of new transmission*

Across all accelerated transmission frameworks and sensitivity cases, the system cost savings exceed the additional cost of building the transmission compared to the Limited scenario. Figure 17 shows the range of benefit-to-cost ratios for the portfolio of transmission investments in the AC, P2P, and MT scenarios for the 90% by 2035 emissions constraint scenarios.[32] The highest benefit-to-cost ratios are achieved in the P2P and MT scenarios that allow for HVDC transmission development. The core P2P and MT scenarios achieve a benefit-to-cost ratio of 1.7 and 1.8, respectively, compared to the core AC scenario benefit-to-cost ratio of 1.6. As with system cost savings, the benefit-to-cost ratios for the core scenarios are toward the lower end of the ranges. Many sensitivity cases have benefit-to-cost ratios close to 2. Sensitivity cases where new low-carbon technologies are not available typically have higher benefit-to-cost ratios (1.9 to 2.3). The benefit-to-cost ratio exceeds 1.5 across all sensitivity cases; for context, the maximum threshold allowed in FERC Order No. 1000 to determine whether transmission facilities have significant enough benefits to be selected in a regional transmission plan for the purpose of cost allocation is 1.25 (Federal Energy Regulatory Commission 2011).[33]

[32] Benefits are defined as the difference in total nontransmission system costs including generation and storage capital and operating costs and policy incentives between the accelerated transmission framework (AC, P2P, or MT) and the Limited framework. Costs are defined as the NPV of transmission capital and operating costs for all transmission types including spurline, intra- and interzonal lines, and converter stations. More information on the cost analysis is provided in Appendix E.

[33] FERC Order No. 1000 specifies that a benefit-to-cost ratio of 1.25 is the maximum threshold for determining if transmission facilities have sufficient net benefits to be included in regional transmission plans.

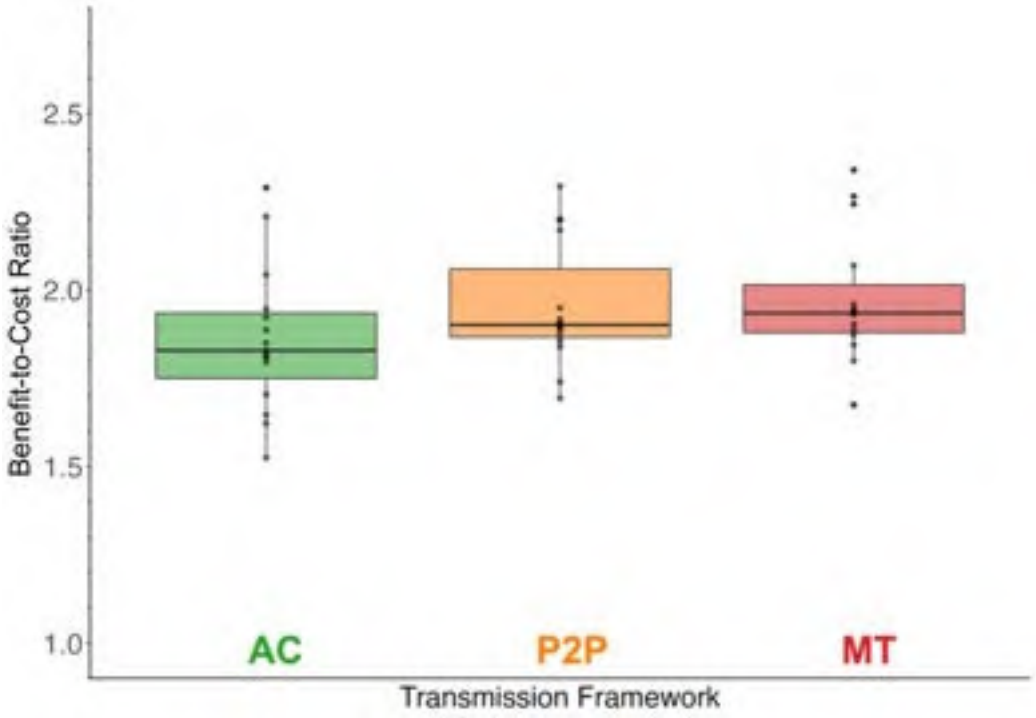



Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

*The center line indicates the median value, and upper and lower box lines indicate the 25th and 75th percentiles, respectively. The benefit-to-cost ratios exclude the added cost of transmission when calculating benefits.*

### *Transmission expansion helps reduce capital, operating, and fuel expenditures for generation and storage*

Historically, savings in production costs have been the primary metric for valuing transmission investments (Chang, Pfeifenberger, and Hagerty 2013; Federal Energy Regulatory Commission 2022). However, transmission development can—positively and negatively—impact a broader range of system costs, including capital investments, fixed operation and maintenance (O&M) costs, and the ability to capture policy incentives. The impact on system costs may change over time as the underlying generation mix changes. Figure 18 shows the change in different types of system costs for the AC, P2P, and MT scenarios compared to the Limited framework from 2025 through 2050.

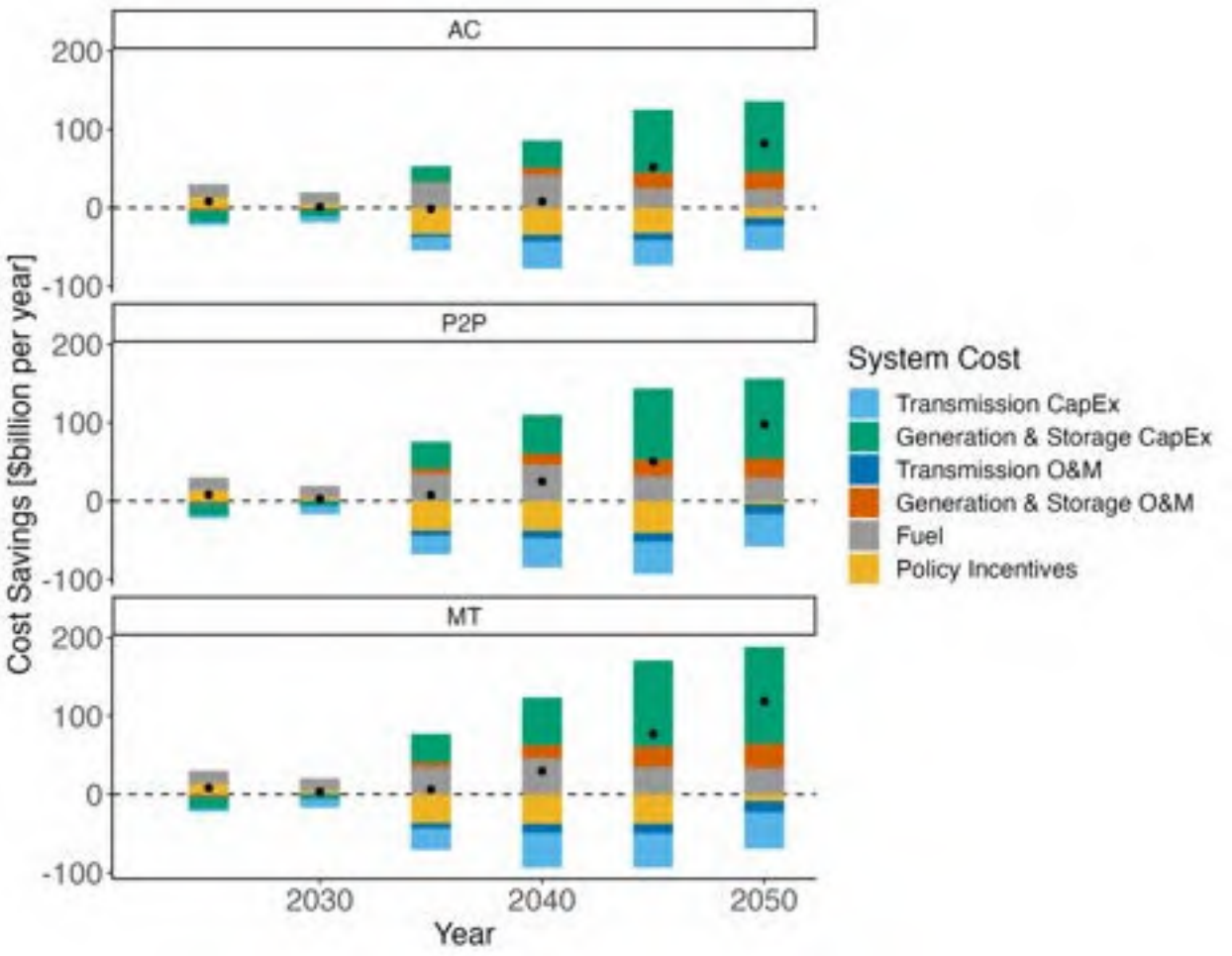



Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

*Negative values indicate greater costs compared to the Limited framework; positive values represent savings. Black dots indicate net savings across all system cost categories.*

Savings in generation and storage capital costs are the largest source of system savings, totaling $420 billion in the AC framework and more than $700 billion in the MT framework (present value), equivalent to an 11%–20% reduction in total generation and storage capital costs. These savings do not begin until after 2030 and increase in magnitude over the planning period. Reductions in fuel costs make up the second largest source of savings because increased investments in transmission enable greater use of VRE resources, resulting in a 44%–49% decrease in fuel expenditures. Annual savings from avoided fuel costs peak around 2040 and start to decline as the share of VRE increases and opportunities to displace fuel generation are reduced.

Though total system costs decrease in the accelerated transmission development scenarios, capital and operating costs for transmission increase compared to the Limited framework as investments in all types of transmission increase. Total expenditures for transmission (present value) are $760 billion; $1,220 billion; $1,320 billion; and $1,390 billion for the Limited, AC, P2P, and MT frameworks, respectively

(Figure 19). Investments and operating costs for local transmission infrastructure make up the largest share of transmission costs, accounting for more than 40% of total transmission expenditures for all transmission frameworks. Investments in interregional transmission are smaller in all scenarios but grow noticeably after 2030 in the accelerated transmission frameworks (AC, P2P, MT) and reach $12 billion per year by 2050. For context, recent historical transmission investments are estimated to be $20–25 billion per year (Edison Electric Institute 2024).[34] Annual fixed O&M costs for transmission infrastructure—assumed to be 1.5% of the upfront capital cost—make up a significant share of total expenditures, accounting for 50% of total transmission expenditures in 2025, falling to 30% by 2050. Increased transmission development also impacts the tax credit outlay, particularly including the production and investment tax credits for wind, solar, and storage as well as the $CO_2$ capture tax credit.[35]

[34] The scope of Edison Electric Institute's estimates may not align with the transmission cost categories. In particular, spur lines and other interconnection investments modeling may not be included in the historical data.

[35] The system cost metric and associated benefit-cost-ratio method includes the value of tax credits (tax credits are treated as negative costs to the electricity system) because this metric is intended to measure the impact from the perspective of the electricity system, including producers. This electric sector perspective differs from an economywide perspective where tax credits are typically viewed as transfers between taxpayers and those receiving the credits. When tax credits are excluded in the cost metrics to be more aligned with this perspective, the system cost savings from accelerated transmission change to $570–830 billion (compared with $270–490 billion) under the core scenarios and the benefit-cost ratios change to 2.2–2.3 (compared with 1.6–1.8).

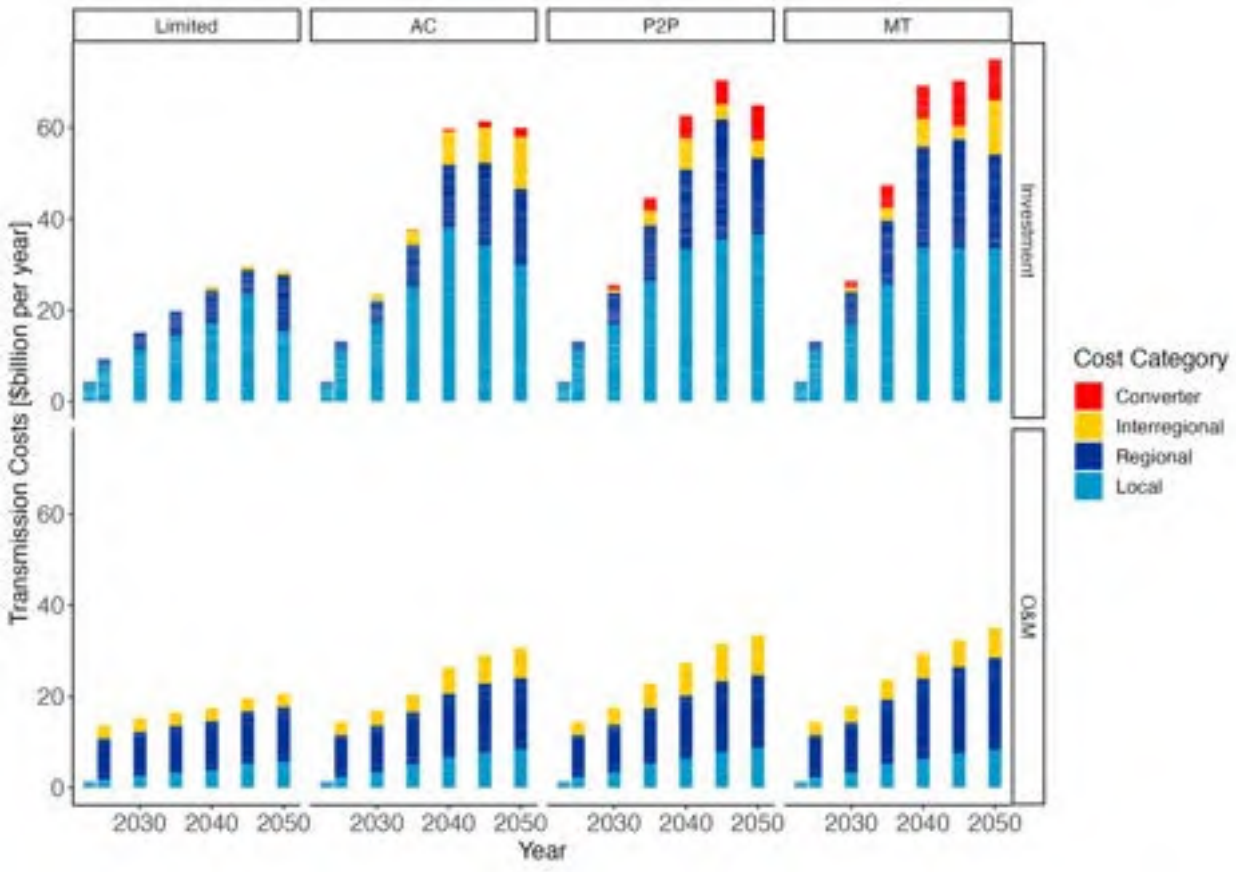



Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

*Investments in converters serve both regional and interregional transmission needs.*

### *Interregional transmission enables cost savings for most regions*

Though the systemwide value and benefit-cost ratio of each accelerated transmission framework are high, they are not uniform across all individual transmission planning regions. When evaluating the benefit distribution among regions, further consideration of where power is exported and imported—and the value of the power traded—is needed to capture the transmission benefits of interregional trade to each region. To disaggregate benefits regionally, operational costs are adjusted to approximate how these costs might be allocated between importing and exporting regions. To do so, the analysis uses the adjusted production cost (APC) metric.[36] This metric is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission investment. For this study, the APC is based on zonal marginal prices from the capacity expansion model. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production costs for each region. The following figures show the total savings to each region

[36] See Appendix E for more details on the APC method used in current planning processes and the adjustment values calculated for the core transmission scenarios.

compared to the Limited scenario by system cost category (Figure 20a) and as a share of each region's costs (Figure 20b).

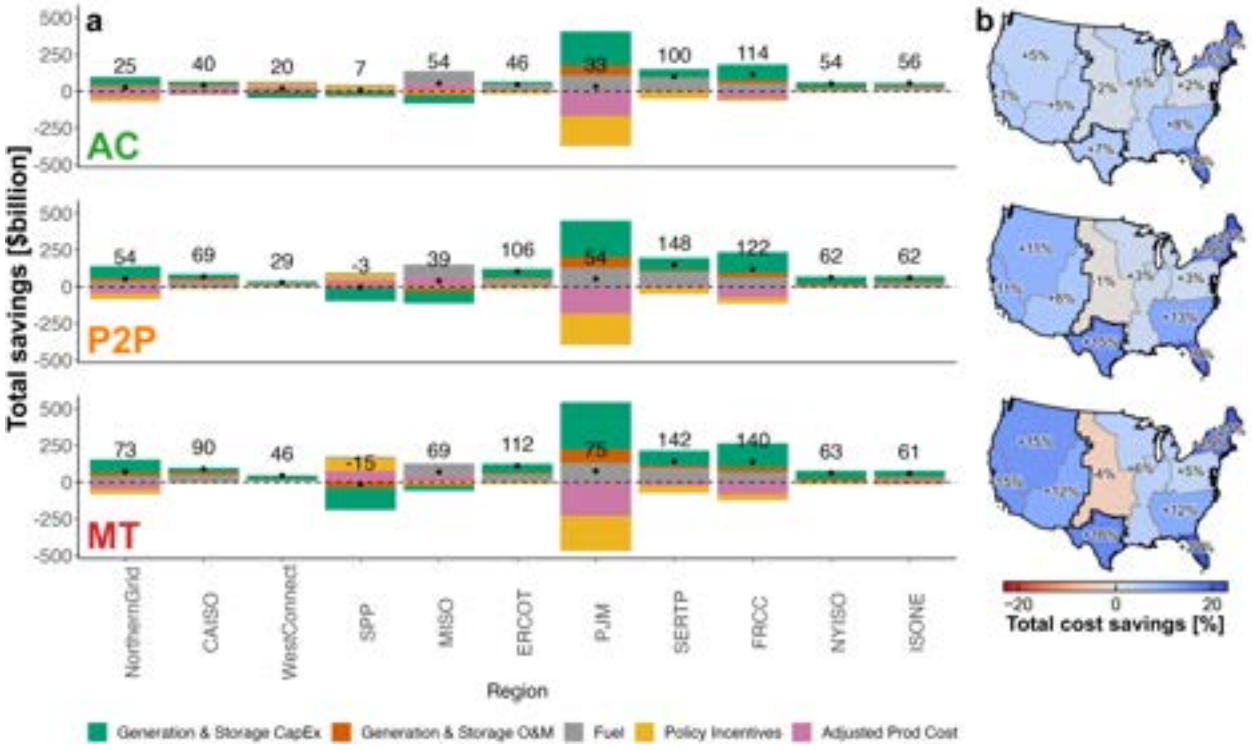



Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

*Black dots in (a) indicate net savings across all system cost categories. These results show the disaggregation of system benefits evaluated as part of this study and are not intended to prescribe any specific cost allocation among planning regions.*

Among planning regions, savings from increased transmission interconnection in 90% by 2035 Mid-Demand scenarios are highest in the Southeast (SERTP, FRCC) and Texas (ERCOT). These regions see large decreases in fuel costs and generation and storage capital costs because the transmission network allows them to make greater use of lower-cost resources located in other regions. As a share of total costs, ISONE, FRCC, and NYISO see the highest savings, with costs declining by more than 20% in the MT framework. In other regions, such as SPP, total costs increase in some scenarios compared to the Limited framework because these regions are building more generation capacity to export to neighboring regions. In these regions, the additional benefits from collecting more investment and production tax credits and increased generation revenues from selling power to neighbors do not outweigh the additional cost of building and operating more generation capacity.

Similar to systemwide cost savings, the regional transmission value—measured by the savings in investment and operating costs transmission can provide—is sensitive to technology availability and costs, climate impacts, siting constraints, and other varying system characteristics. Figure 21 shows the range of transmission values by region across all sensitivity cases using the Mid-Demand 90% by 2035 assumptions.

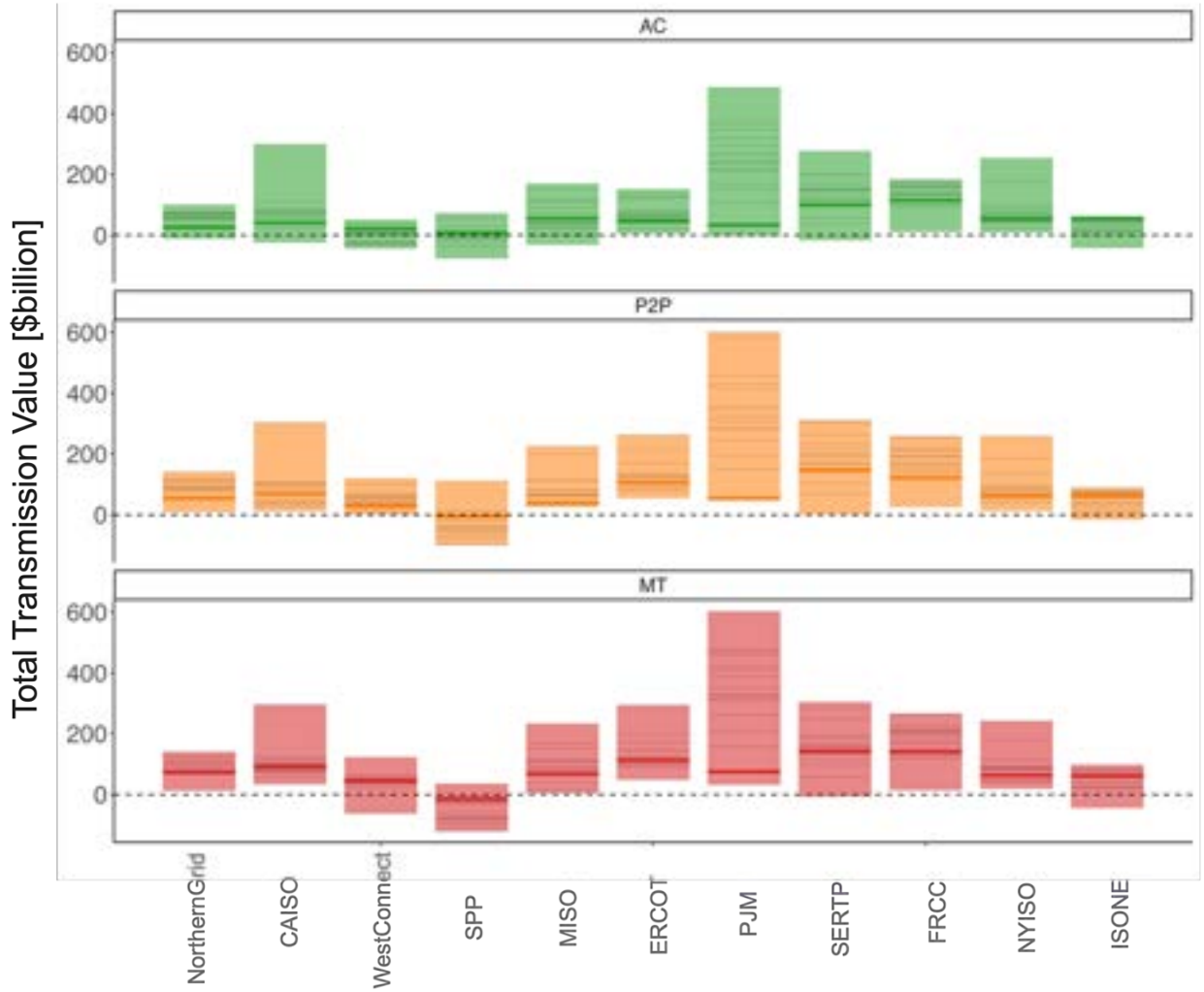



Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

*Bold line indicates the core scenario result.*

The impact of each sensitivity varies by region. For example, in regions that rely on CCS and $H_2$ technologies to achieve emissions reductions targets, the value of transmission increases when these technologies are not available. Detailed results for each modeled sensitivity are presented in Appendix D.4.

### 3.3.2 Transmission expansion enables increased access to wind and solar

As in the Current Policies scenarios (Section 3.1), accelerating transmission expansion increases the share of VRE in the resource mix across all sensitivity cases (Figure 22). The VRE share (annual solar and wind generation divided by total annual generation from all sources) is ~20% higher in the AC, P2P, and MT core scenarios (77%–82% VRE share) than in the Limited core scenario (58% VRE share).

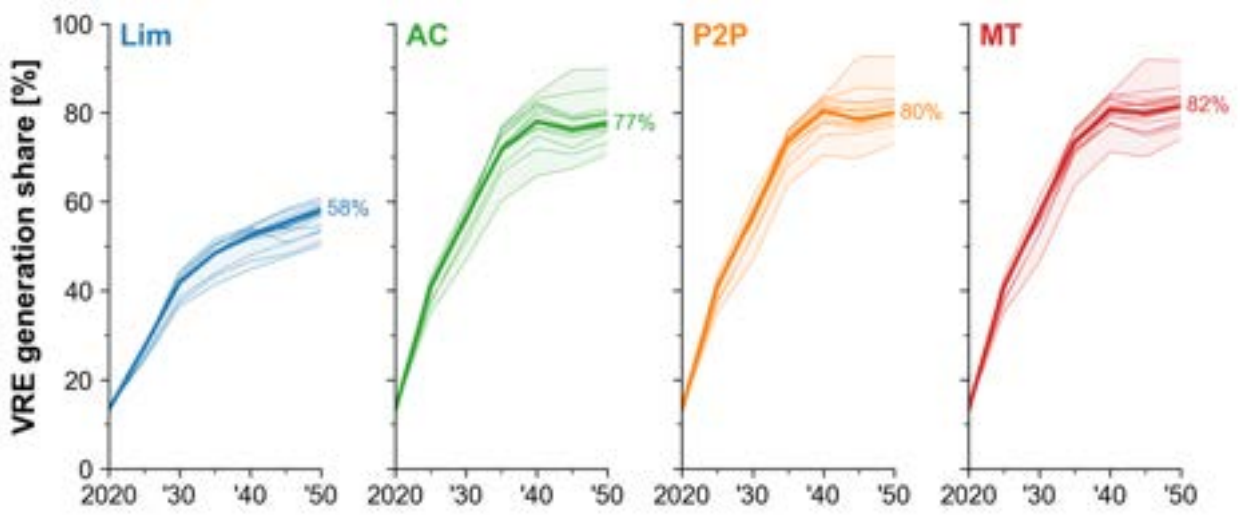



Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

*Core scenarios are shown by a thick line, with the 2050 value labeled; sensitivity cases are shown by thin lines, with the shaded area showing the range between sensitivity cases.*

There is considerable spread in 2050 VRE share across sensitivity cases for a given transmission framework, but the sizable increase in VRE through accelerated transmission is consistently observed across all sensitivity cases. The 2050 VRE share in the Limited framework ranges from 50% to 61% across sensitivity cases, versus 71%–90% in the AC framework, 73%–93% in P2P, and 74%–92% in MT. Excluding the "No CCS," "No $H_2$ or CCS," "No $H_2$," and "No $H_2$ or new nuclear" sensitivity cases, the nuclear generation share ranges from 16% to 27% in the Limited framework and 6% to 9% in the accelerated transmission frameworks. The generation share from fossil generation with CCS ranges from 12% to 18% in the Limited framework and 2% to 11% in the accelerated transmission frameworks. Figure 23 shows the 2050 generation mix for all sensitivity cases. The capacity mix for all sensitivity cases is shown in a similar format in Figure D-10.

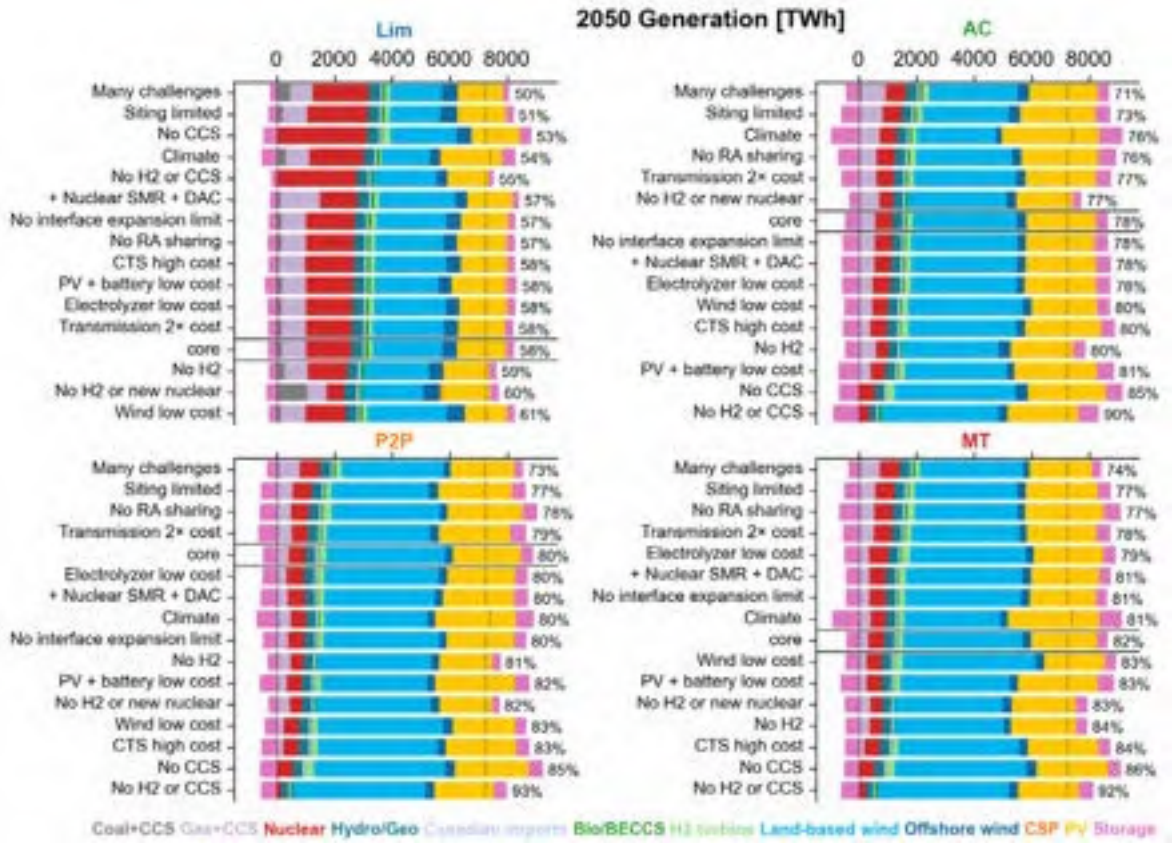



Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

*Within each transmission framework, the sensitivity cases are sorted by 2050 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.*

### 3.3.3 Significant amounts of transmission are added at all scales (local, regional, and interregional) in decarbonized systems

#### *When transmission additions are limited, local generator interconnection takes precedence over longer-distance transmission*

Both long-distance and local transmission expansion play large roles in the lowest-cost decarbonized power systems (Figure 24). But in the Limited transmission framework, where annual total transmission additions are limited to 1.83 TW-mile/year, the large majority of the limited "budget" for transmission additions is used for local interconnection of new wind and solar resources in both the core scenarios (Figure 24) and sensitivity cases (Figure 25). Roughly 92% of total transmission additions between 2020 and 2050 in the Limited framework is associated with local interconnection. As the availability of new long-distance transmission increases, this fraction drops—to 56% in the AC framework, 42% in the P2P framework, and 31% in the MT framework—although the absolute amount of new interconnection capacity is greater in the accelerated transmission frameworks (110–120 TW-miles) than in the Limited framework (~50 TW-miles), reflecting the larger renewable energy share in these scenarios.

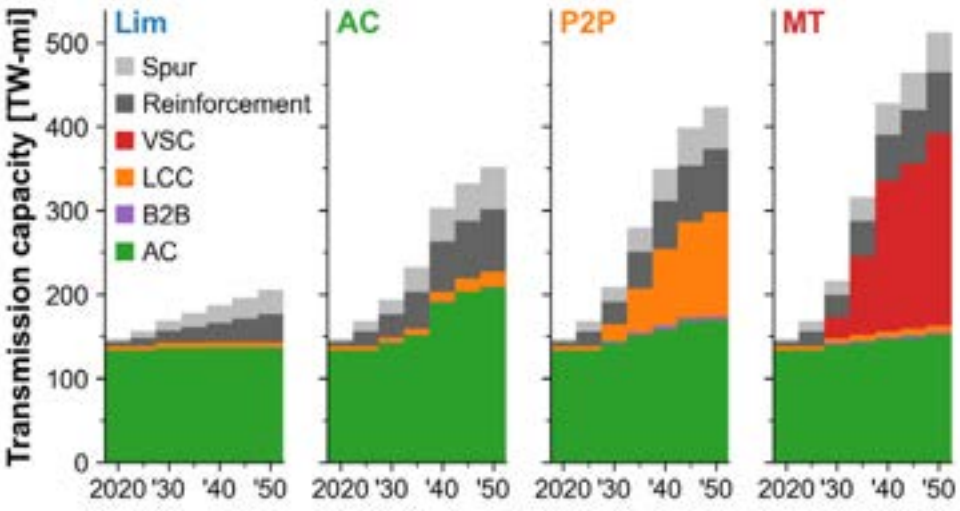



Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

*Local transmission for wind and solar interconnections includes both spur and reinforcement capacity. Other categories are for interzonal transmission.*

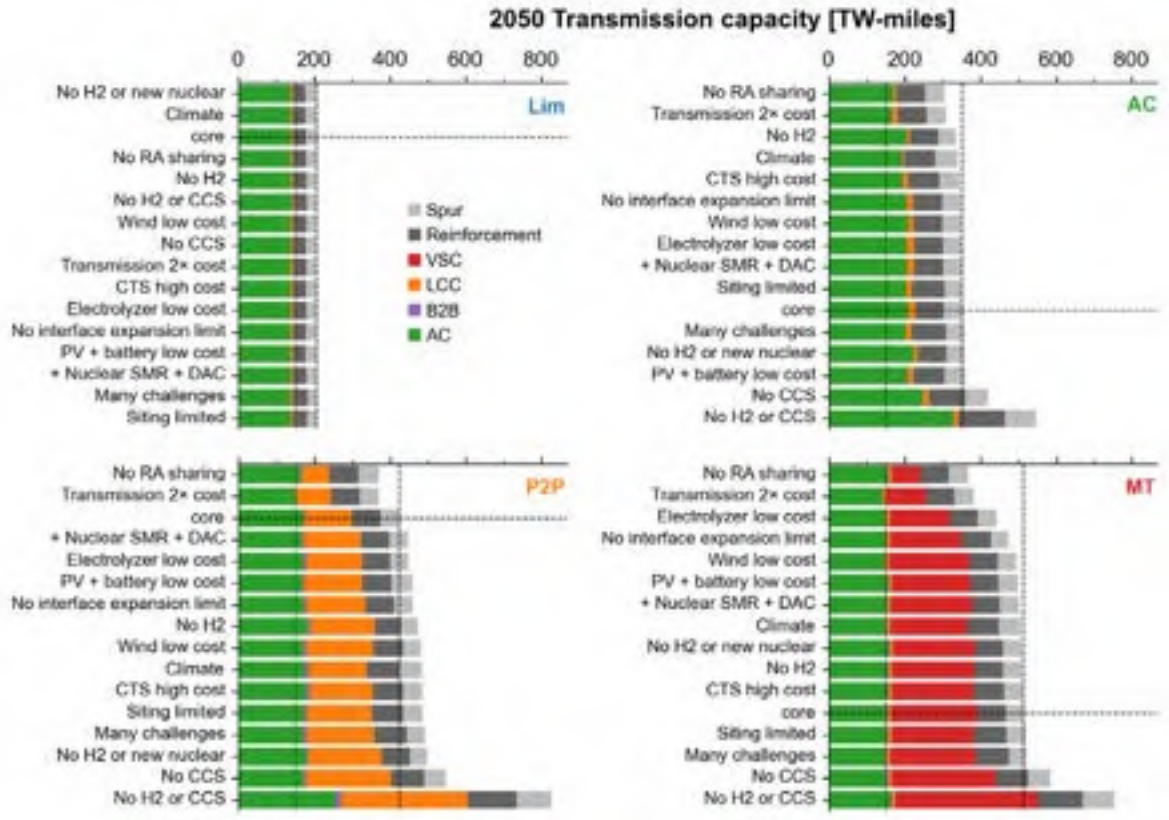



Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

*Values for the core scenarios for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2050. The lighter vertical dashed line shows the 2020 capacity (~150 TW-miles). The 1.83-TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2050 transmission capacity the same in all sensitivity cases for this framework.*

### *If available, HVDC transmission additions outpace AC additions for long-distance transmission*

Both AC and HVDC transmission additions are allowed in the P2P and MT frameworks, but HVDC additions significantly outweigh interzonal AC additions in all sensitivity cases in these frameworks (Figure 25). The amount of new HVDC capacity added through 2050 is 2.3–6.0 times the amount of new interzonal AC capacity in the P2P framework and 3.9–16 times in the MT framework. ReEDS does not explicitly model AC power flow or the implications of DC protection on system design; the choice between AC and DC for interzonal transmission investments is thus driven solely by $/MW cost (including the cost of AC/DC converter stations and associated reactive power support) and losses, both of which are lower for DC than AC when distances exceed ~200–500 miles (Alassi et al. 2019).

## 3.3.4 Expansion of interregional transmission is significant in decarbonized systems

### *Expansion of long-distance transmission is concentrated in the central part of the country*

Previous studies have noted the synergy between transmission and wind deployment (P. R. Brown and Botterud 2021; Denholm et al. 2022); because wind capacity factors exhibit greater spatial variability than solar capacity factors (Figure 26) and because daily solar variability is well-matched with short-duration storage, transmission deployment tends to be correlated with wind deployment and storage deployment tends to be correlated with solar deployment (Blair et al. 2022; Frazier et al. 2021). A similar relationship—that the greatest density of new long-distance (interzonal) transmission additions occurs around the midwestern “wind belt” (Figure 26, Figure 27)—is observed in the scenarios. The trend is most pronounced in the AC transmission framework, where three multilink connections are observed between the wind belt and demand centers in the Southwest, Midwest, and Southeast. A greater amount of long-distance transmission overall is added in the P2P and MT frameworks, but most of the largest links have an endpoint in the wind belt. Though some north-south additions are observed, most new long-distance transmission capacity is oriented predominantly east-west.

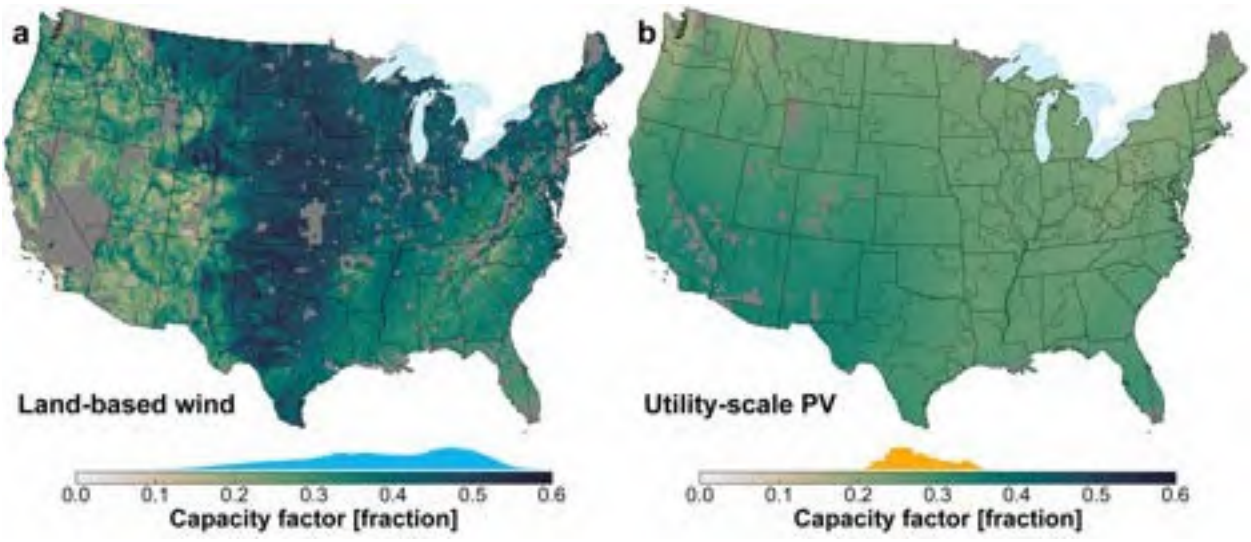



Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

*Both maps assume Reference Access siting (Appendix A); sites without developable capacity are shown in gray. Both maps show AC capacity factor using the same color scale range. The "wind belt" refers to the darkest-colored (highest-capacity-factor) region in the wind map extending from north to south through the center of the country. Histograms above color bars indicate the frequency of occurrence of the indicated capacity factor values across the ~50,000 reV model sites shown in the corresponding map.*

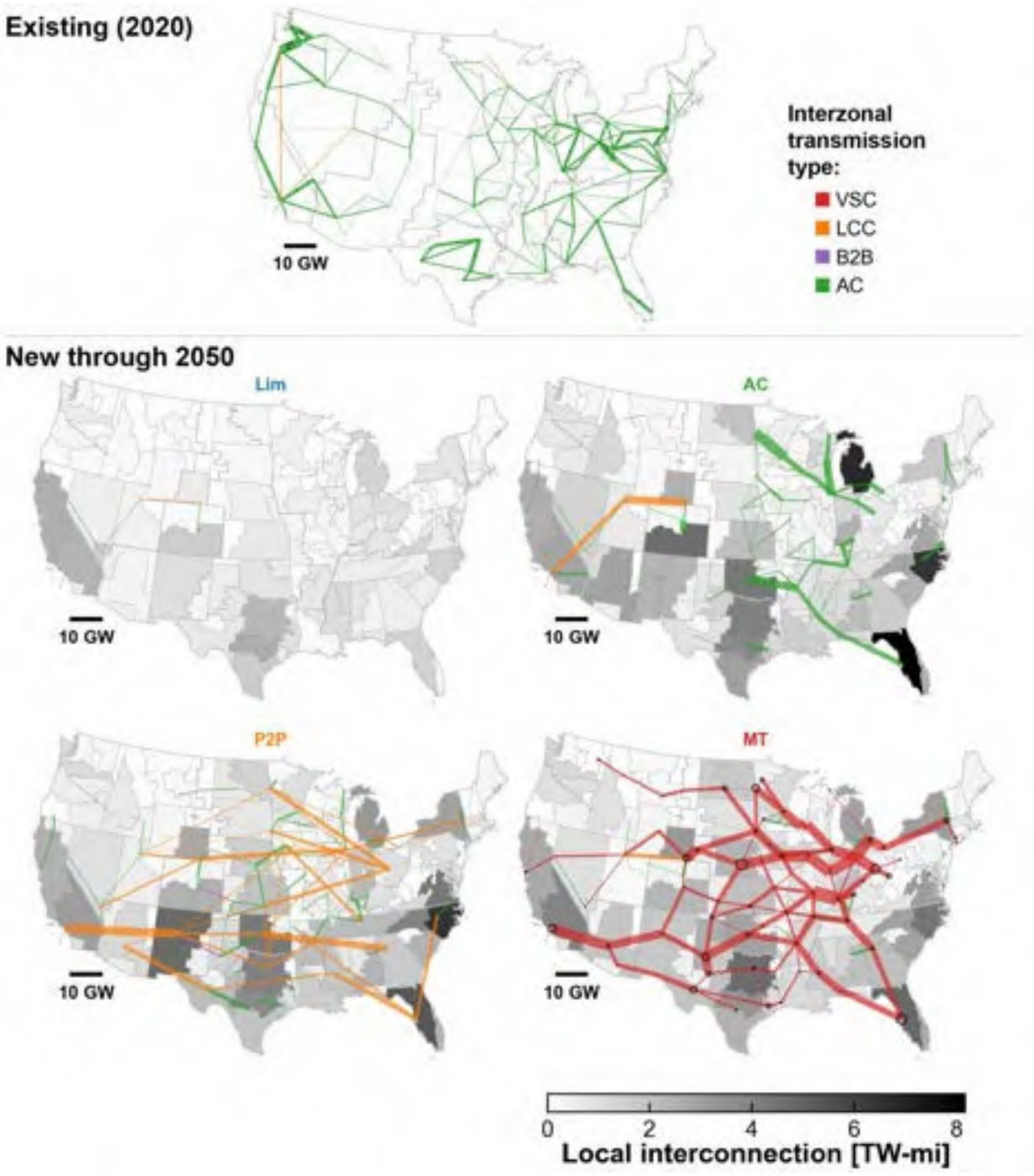



Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

*Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.*

The MT scenario tends to make the most efficient use of AC/DC converter capacity. Some zones have minimal converter capacity (indicated by the small black circles in Figure 27), instead acting primarily as pass-throughs in the HVDC network, while exporting zones (in the wind belt) and importing zones (in southwestern and eastern demand centers) install converters sized to their usage needs. The P2P scenario, on the other hand, may make more efficient use of transmission rights-of-way by using higher-voltage (thus higher-power-capacity) LCC architectures (Alassi et al. 2019), although transmission land use is not directly considered here.

Regional transmission trends can be summarized at the planning region level using the ratio of “transfer capability to other planning regions” (GW) to “peak demand within the planning region” (GW) (Figure 28). A range of interregional transfer capabilities is observed in the current (2020) system: ERCOT has a transfer capability ratio of 0.01; ISONE, SERTP, and FRCC range from 0.1 to 0.3, and other regions range from 0.3 to 0.7. In the Limited transmission framework, new additions of interregional transfer capacity are not allowed; thus, as peak demand increases over time, the transfer capability ratio falls. In the AC framework, many regions maintain transfer capability ratios similar to their 2020 values, although there are notable increases in SPP and MISO. The transfer capability ratio increases dramatically for the wind-rich regions of SPP, MISO, and WestConnect in the MT transmission framework, reaching ~2.6 for SPP and ~1.8 for MISO and WestConnect. When interconnection-seam-crossing capacity additions are allowed in the two HVDC scenarios, the transfer capability ratio in ERCOT increases to roughly 0.3, on par with other regions with stronger existing connections to neighboring regions.

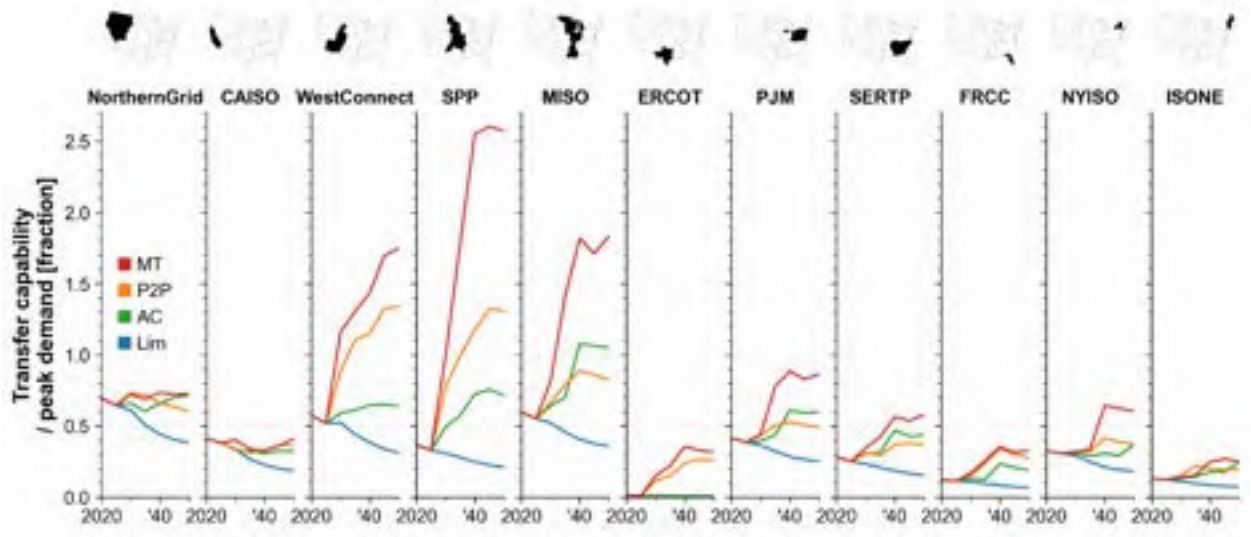



Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

*Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.*

### *When allowed, transmission capacity expands significantly across the three interconnection seams*

Though many interregional interfaces host large transmission capacity additions in the decarbonization scenarios, the interconnection "seams" demonstrate particularly large capacity additions relative to their currently small transfer capability (Figure 29). New seam-crossing capacity is not allowed in the Limited or AC frameworks but expands to ~80 GW by 2050 in the P2P framework (~37 times the currently installed seam-crossing capacity of 2.1 GW) and ~110 GW (~50 times) in the MT framework. By 2035, the seam-crossing capacity reaches roughly half of its 2050 value: 44 GW in P2P and 52 GW in MT. Transmission capacity is added across each of the three seams in both HVDC frameworks.

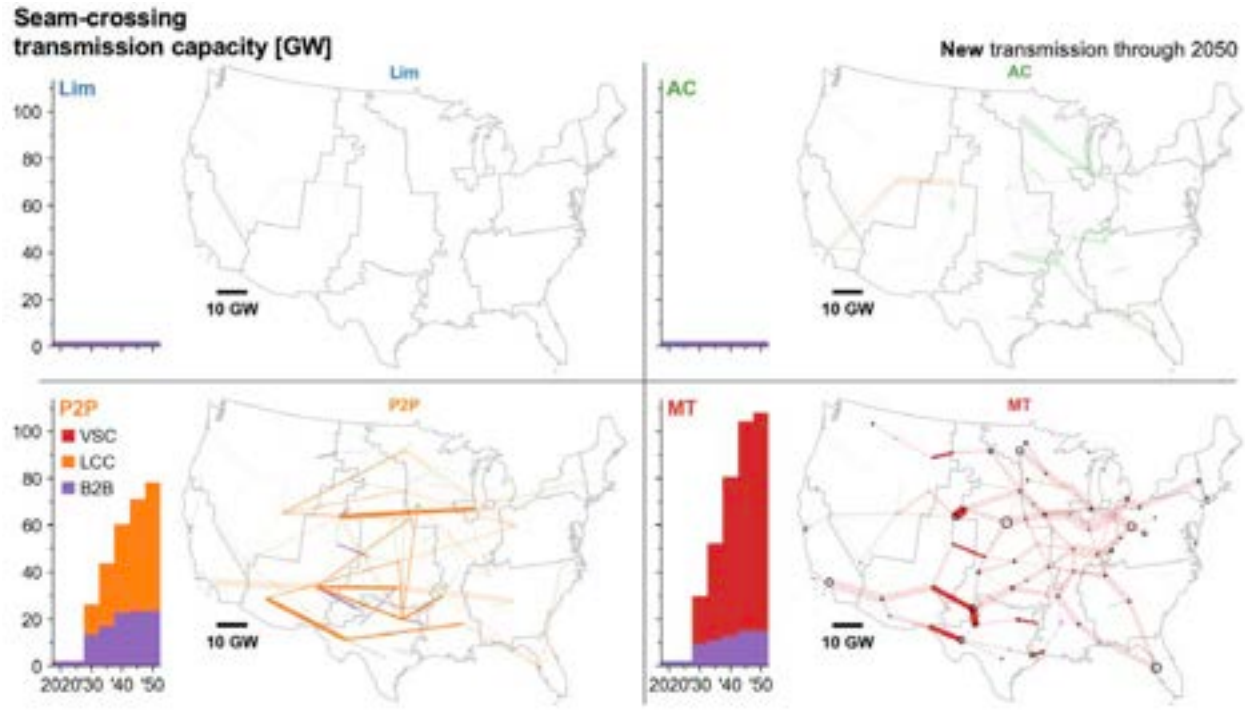



Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

### *Spatial patterns in transmission expansion are similar across many sensitivity cases*

The transmission deployment maps shown thus far have used core scenario assumptions, but there is significant uncertainty in the projected cost and availability of different technologies between now and 2050. It is therefore important to understand whether the spatial trends discussed thus far vary under different assumptions regarding technology evolution, here parameterized through the 15 sensitivity cases described previously. Though the absolute amount of transmission capacity deployed varies substantially across sensitivity cases for a given transmission framework (Figure 25), the spatial distribution of new long-distance transmission is largely consistent (Figure 30, Figure 31, and Figure 32). The greatest density of long-distance transmission additions is observed around the wind belt, and the orientation of new long-distance transmission additions (particularly in the P2P and MT frameworks) is predominantly east-west.

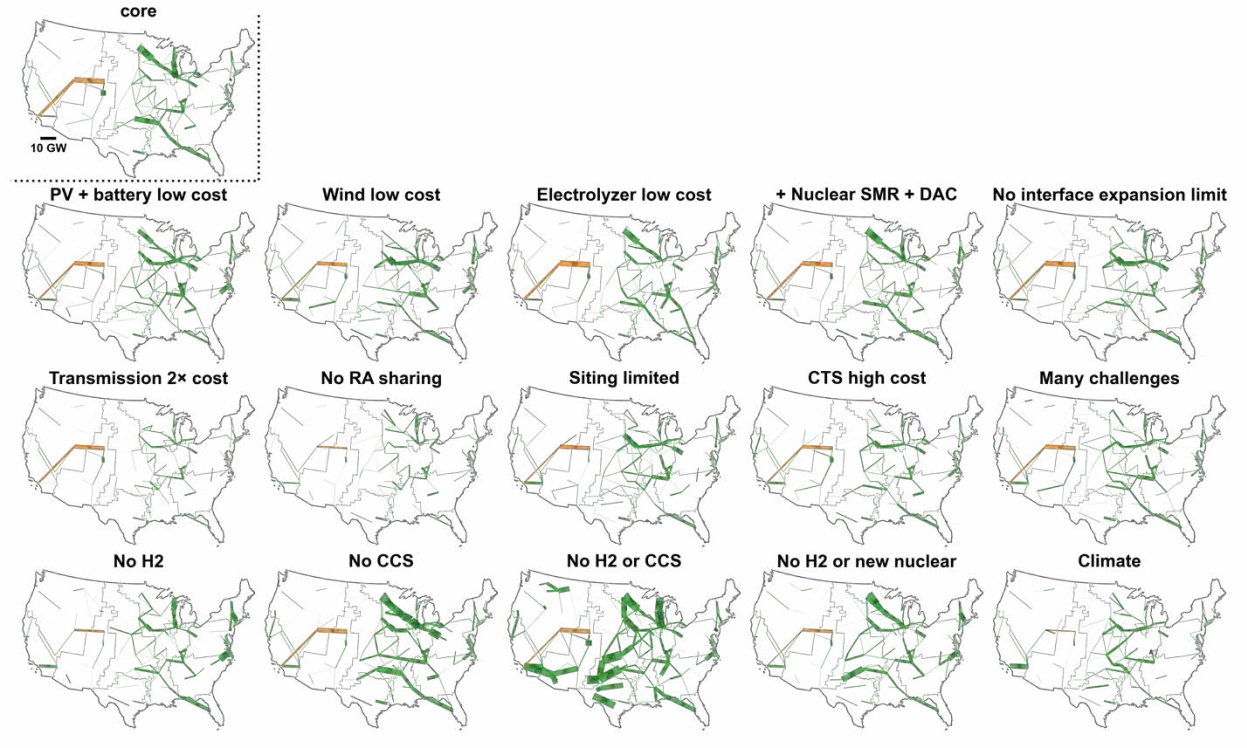



Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

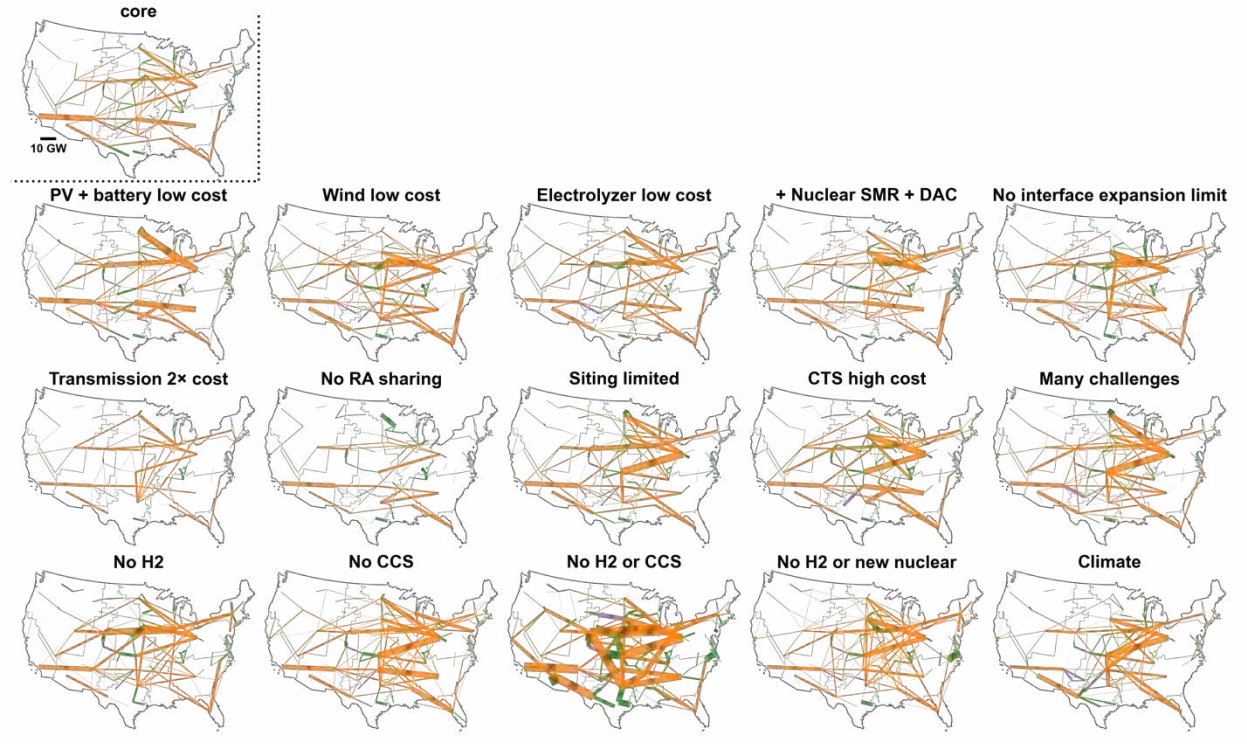



Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

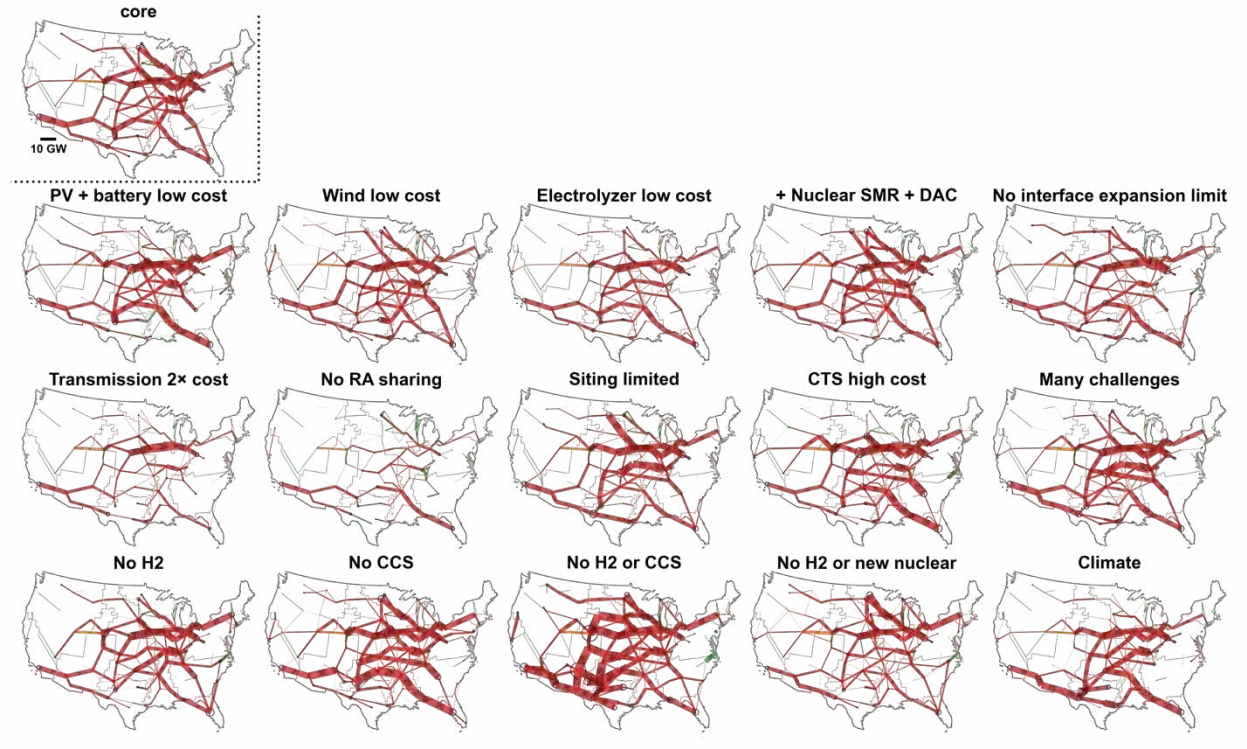



Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

Figure 30, Figure 31, and Figure 32 visually demonstrate the similarity in the spatial trends in transmission development across the sensitivity cases modeled. The following text box presents an analysis that more systematically evaluates interregional transmission expansion in these scenarios to identify subregional High Opportunity Transmission (HOT) interfaces from the scenarios. The HOT interfaces serve as an initial screening to determine how much and where additional high-capacity transmission may be needed between the subregional pairs given the full set of sensitivity cases considered here.

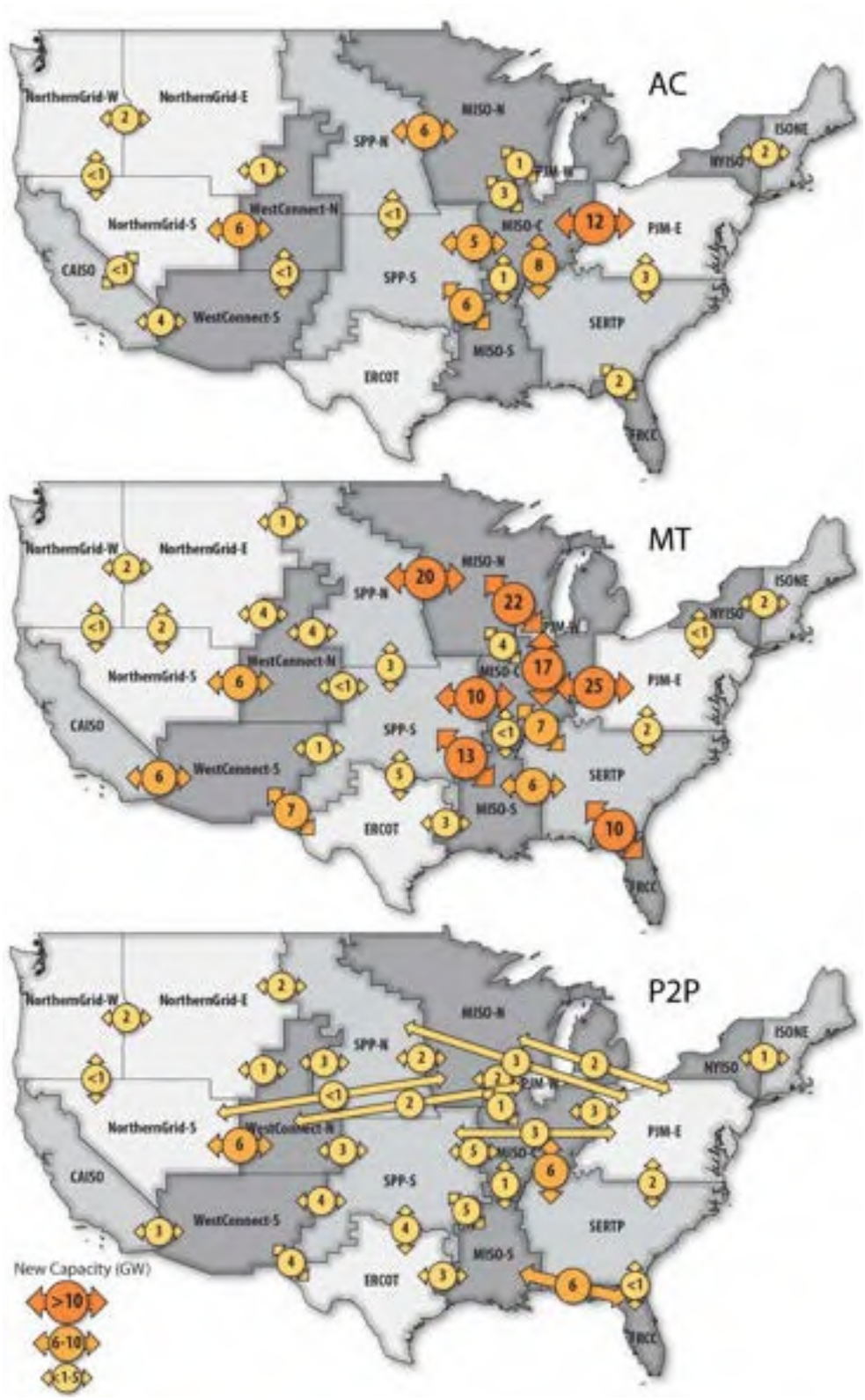
**High Opportunity Transmission**

An objective of the NTP Study is to identify potential transmission solutions that will provide broad-scale benefits to electricity customers under a wide range of potential futures. To support this objective, this text box presents a screening analysis to identify High Opportunity Transmission (HOT) interfaces between planning subregions developed using the scenarios presented in this chapter.

Subregional HOT interfaces are specified by the amount of transfer capacity expanded between a pair of planning subregions (Figure 1b) from 2020 to 2035. These interfaces are found by systematically evaluating this transfer capacity increase from the 16 scenarios (one core scenario plus 15 sensitivity cases) under the central demand/emissions assumptions (Mid-Demand, 90% by 2035) for each of the three accelerated transmission frameworks (AC, P2P, and MT). Specifically, a HOT interface capacity is defined as the expansion between subregions that occurs in 75% of the scenarios, i.e., the 25$^{th}$ percentile of transmission expansion. This 25$^{th}$ percentile is chosen to reflect robustness in development across a wide range of future conditions about technology costs and availability, renewable energy siting, and level of interregional coordination.

The following maps show HOT interfaces identified for the three accelerated transmission frameworks. In all frameworks, HOT interfaces are found for all regions although a concentration is found in MISO and neighboring regions. The HVDC frameworks (P2P and MT) generally have more HOT interfaces, and their capacities tend to be greater than those in the AC framework. The P2P framework includes long-distance connections, including between nonadjacent planning regions. The MT framework has the highest-capacity HOT interfaces with several having an increased transfer capacity of 10–25 GW. Although some HOT interfaces have very high capacities, a significant fraction of the benefits of interregional transmission can be realized with a smaller amount of expansion as revealed from a side analysis that tests the same scenarios with maximum limits on transmission development across major subregions.

Appendix F provides additional information for the HOT interfaces for each planning region. It also includes the 50$^{th}$ and 75$^{th}$ percentile results to inform more ambitious transmission development opportunities. The HOT interfaces are found by systematically examining the capacity expansion scenarios but are limited by the number and type of sensitivity cases modeled. Additional sensitivity cases would increase the robustness of the interfaces identified, and further assessments are required to determine the viability of any individual project that may align with the HOT interfaces shown. Nonetheless, these subregional HOT interfaces provide a general scale of how much new interregional transmission capacity is needed over the next decade to realize many of the decarbonization scenarios envisioned.




High Opportunity Transmission interfaces with Mid-Demand 90% by 2035 assumptions under the (top) AC, (middle) MT, and (bottom) P2P transmission frameworks

### 3.3.5 Zero-carbon power systems dominated by variable renewable energy can meet resource adequacy targets

The NTP Study uses a coupled ReEDS-PRAS modeling approach, described above, which results in power system reliability levels (for systems with net zero carbon emissions and generation mixes dominated by VRE) that fall comfortably within the range of resource adequacy targets used in industry (Figure 33). The median NEUE for the Mid-Demand 90% by 2035 scenarios across all model years, transmission frameworks, and sensitivity cases (384 total observations) is 0.9 ppm, well below the industry target range of 10–30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In 2045 and 2050—the years in which these scenarios are constrained to net zero electricity system emissions—the median NEUE stays similarly low.

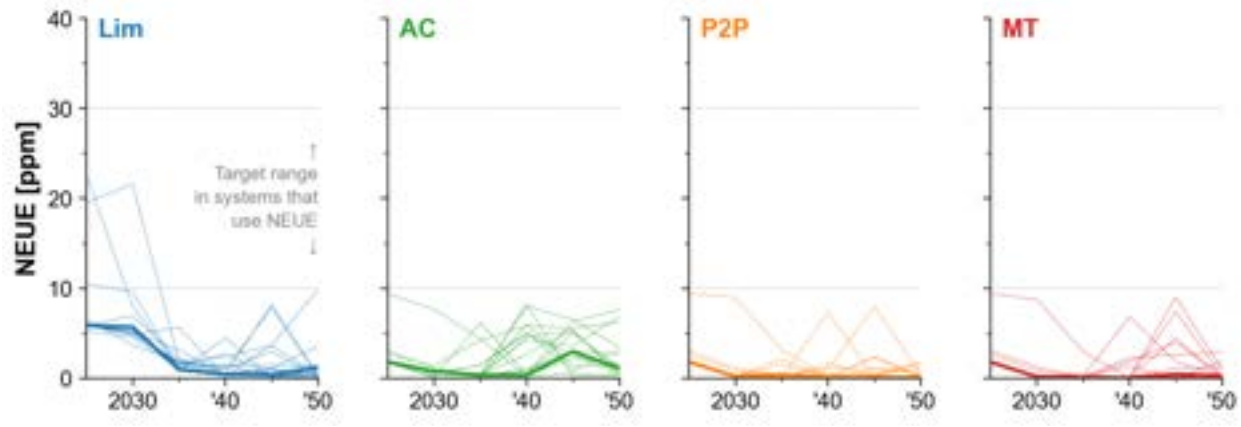



Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

*Results for the core scenarios are indicated by thick lines; results for sensitivity cases are indicated by thin lines.*

Because systems are planned to ensure a minimum RA target is met, there is no trend in RA outcomes between transmission frameworks. Instead, the value of transmission for RA is realized as the change in cost of meeting RA needs, discussed in Section 3.3.1.

#### *A variety of technologies supports resource adequacy*

As discussed in Section 2.1 and Appendix B, the coupled ReEDS-PRAS model addresses RA requirements by identifying “stress periods” with a high risk of unserved energy and including them in the co-optimization of generation, storage, and transmission capacity/operation in ReEDS. Though the nameplate capacity and average generation mix of the decarbonized systems explored here are dominated by wind and solar (Figure 23), wind and solar make up a smaller share of the generation mix during stress periods than during representative periods[37] (Figure 34). Hydropower and thermal technologies, conversely, make up a larger share of the generation mix

[37] Low availability of wind and/or solar on a given day can be the reason that day qualifies as a stress period.

during stress periods than during representative periods. These results show that all technologies—including wind and solar—contribute to the energy and RA needs although the relative contributions between technologies can vary significantly.

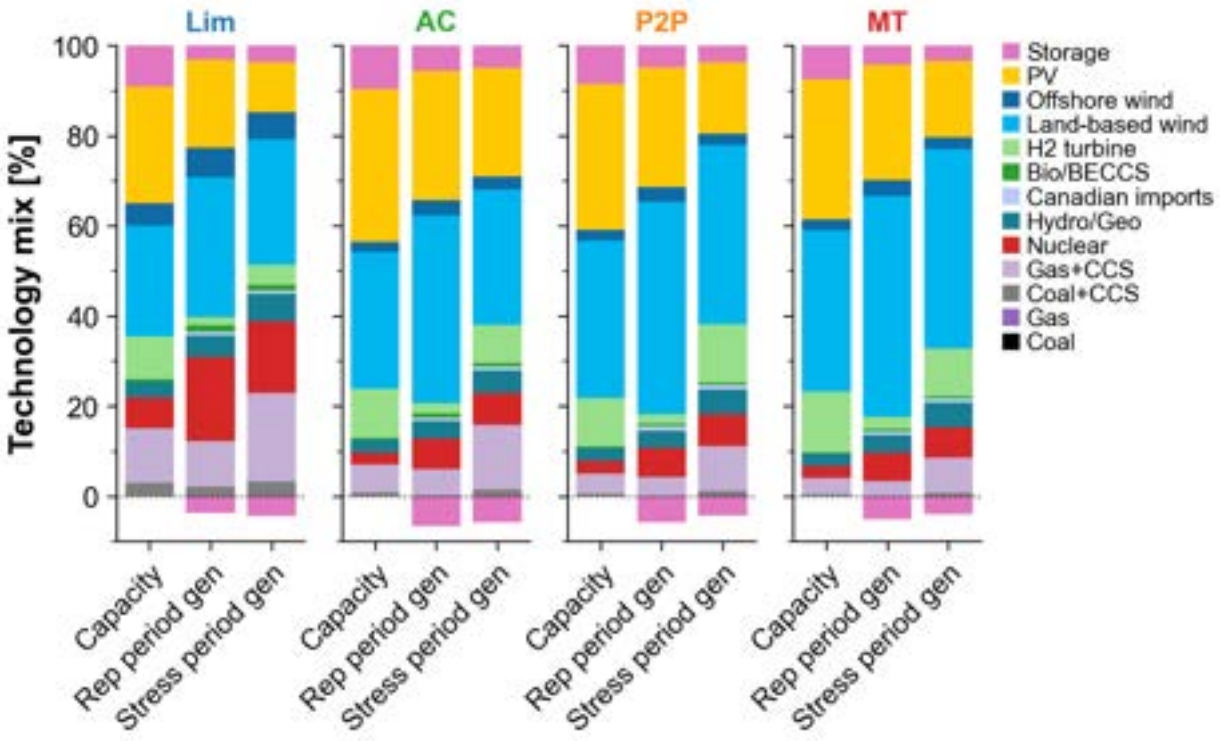



Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

*Stress periods in this study are modeled as coincident 24-hour days over the contiguous United States.*

Though wind and solar contribute more to the bulk energy mix (the "Rep period gen" bars in Figure 34) than to the stress period resource mix, accelerating transmission deployment increases the contribution of wind and solar to the resource mix during stress periods. In the Mid-Demand 90% by 2035 scenario in 2050, wind and solar constitute 44% of the stress-period generation mix in the Limited transmission framework and 57%–64% in the accelerated transmission frameworks. The generation fractions provided here are for all hours of the modeled stress periods and for the contiguous United States as a whole; in particular hours and regions, the contribution of wind and solar can be much smaller (e.g., during low-wind or nighttime hours), and hydro/thermal technologies make up a larger share (Figure 35).

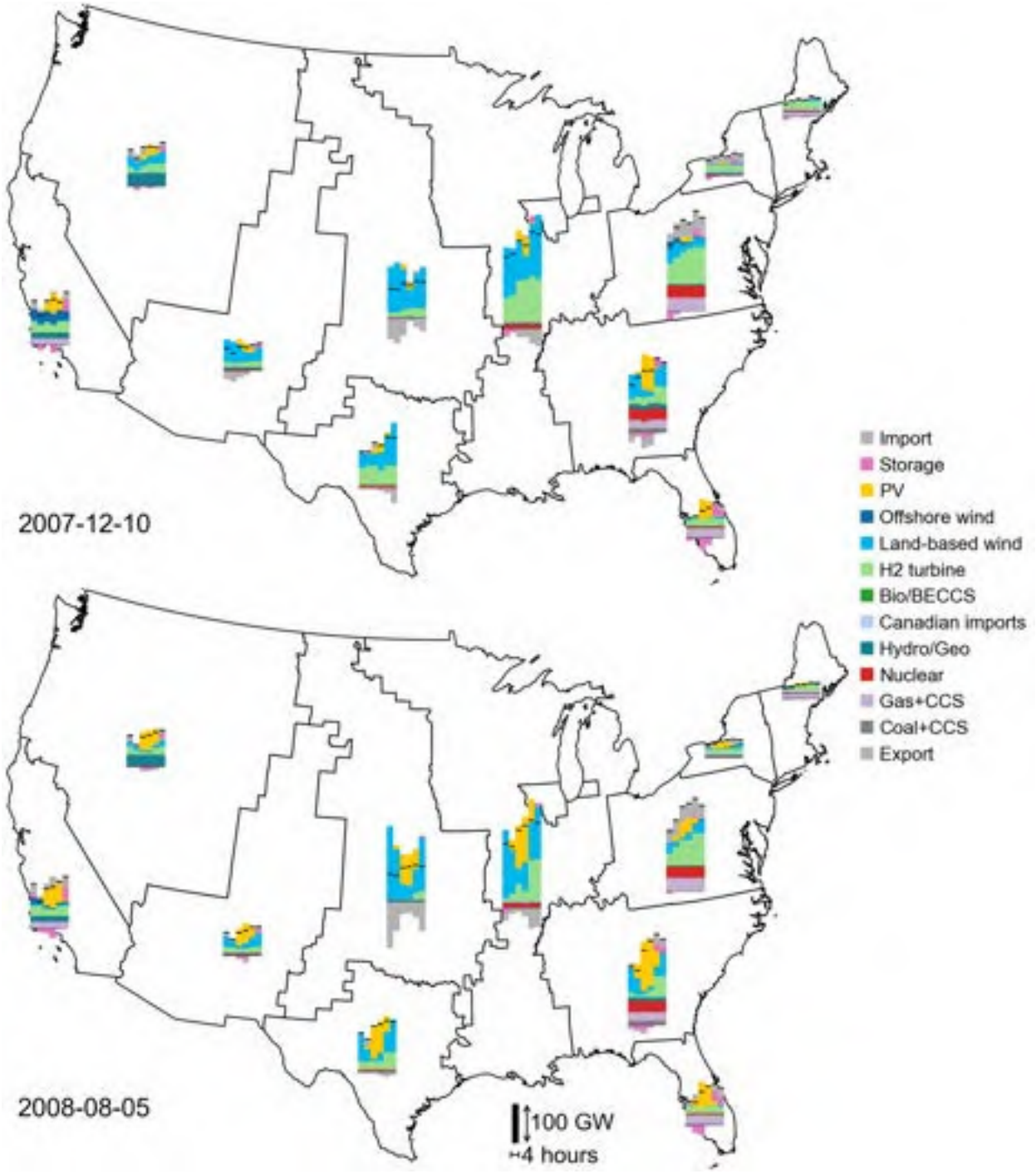



Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

*Dates in this figure are given as year-month-day. The dates shown here refer to weather days from the 2007–2013 weather sample; the capacity and demand mix are for the 2050 model year. 2007-12-10 is the stress period with least VRE generation; 2011-08-05 is the stress period with peak load. Regional load is indicated by thin black lines. Storage charging and exports to other regions are shown as negative values. Daily profiles are at the 4-hour resolution used within the ReEDS model for this study.*

### *Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability*

Figure 34 shows wind and solar make up a larger share of the stress period generation mix in the accelerated transmission frameworks than in the Limited framework. Though improved access to high-quality resource regions with uniformly higher capacity factors explains part of this trend, interregional transmission also smooths out the geographic variability of these weather-dependent resources, particularly for wind (Kempton et al. 2010; Grams et al. 2017; Goggin 2021).

On the least-windy day in the weather dataset for a given planning region, neighboring regions are often significantly windier (Figure 36). For example, on ERCOT's least-windy day (2012-09-15), when the daily average capacity factor of ERCOT wind is only 6%, the wind capacity factor is 31% in neighboring SPP and 34% in MISO (a ~5 times difference). For CAISO, where daily wind capacity factor drops to 2% on 2013-11-17, the capacity factor in neighboring WestConnect and NorthernGrid is 40%–45%, ~20 times higher. These opportunities are sometimes bidirectional: On WestConnect's least-windy day (7% on 2010-12-05), neighboring CAISO has a wind capacity factor of 42%, ~6 times higher.[38]

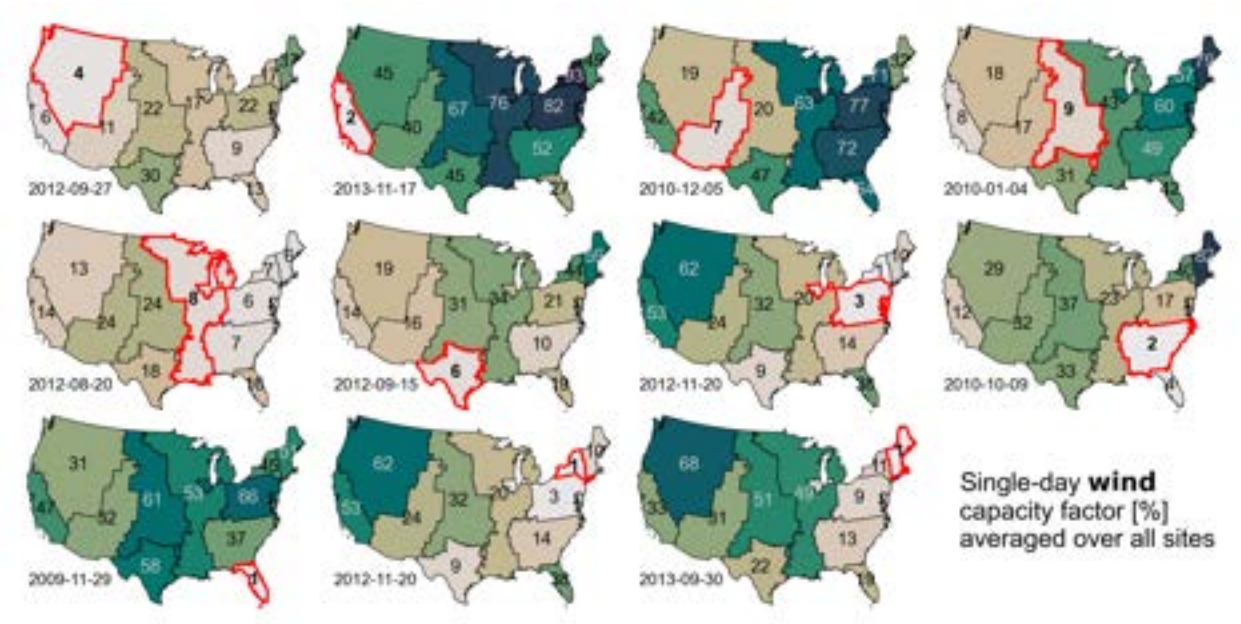



Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

*For each map, the focused planning region is outlined in red, the date of the least-windy day in that region is given in the lower left, and the values and colors in each region represent the daily wind capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.*

[38] Complementarity between different resource types—illustrated in Figure D-14—provides further flexibility: On 2012-08-20, MISO and all its eastern neighbors aside from FRCC have wind capacity factors ≤8%, but solar capacity factor in these regions is above average on this summer day.

Similar examples can be observed for solar (Figure 37), though to a smaller degree than for wind given the uniformly greater seasonal variability of solar (all of the lowest-regional-capacity-factor days for solar occur during winter, with fewer hours of sunlight available regardless of weather). Though there are some strong resource-sharing opportunities—on MISO's least-sunny day (1% on 2009-12-24), the capacity factor in neighboring PJM is ~10 times higher—there are also days when large fractions of the country have uniformly low resource: On 2007-12-28, no planning region east of SPP has higher than a 6% capacity factor. On ISONE's least-sunny day (1% on 2012-12-10), resource sharing would have to extend to MISO or SERTP to reach ≥5% capacity factor.

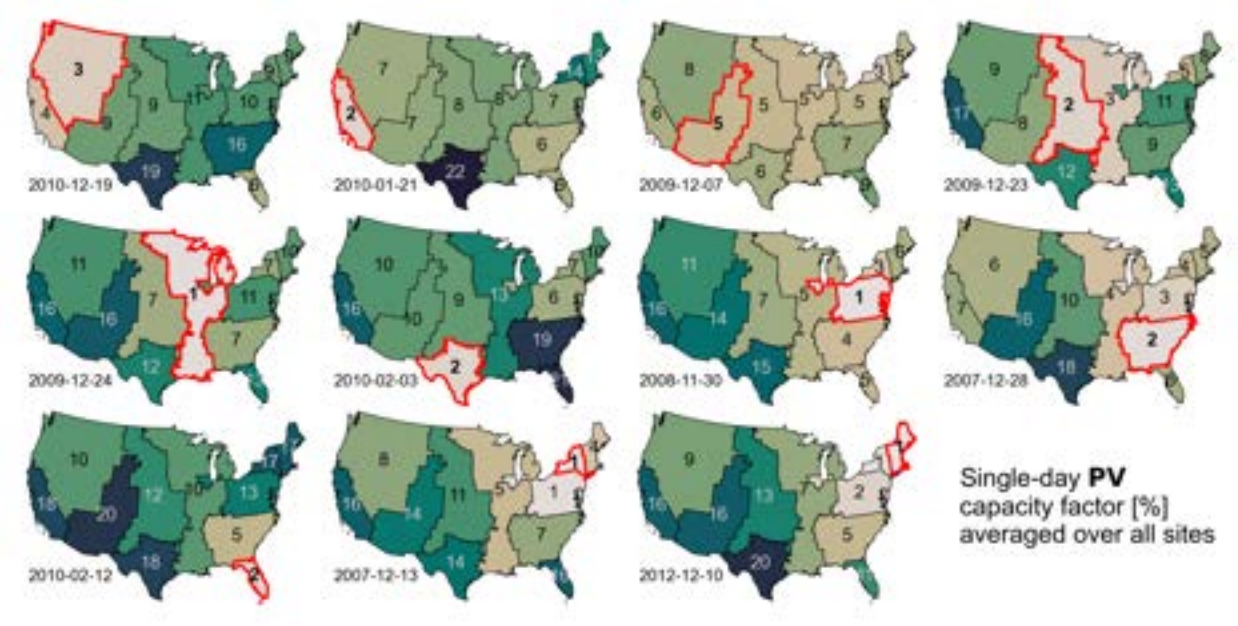



Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

*For each map, the focused planning region is outlined in red, the date of the least-sunny day in that region is given in the lower left, and the values and colors in each region represent the daily PV capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.*

Electricity demand also demonstrates interregional variability, which can be smoothed by interregional transmission (Figure 38) although the opportunities are less pronounced than for wind and solar. Here, if adjacent planning regions reach peak demand on different days, they could have spare capacity to assist neighboring regions in meeting their peaks. The greatest opportunity observed in the Mid-Demand scenario for 2050 is on MISO's peak day of 2009-01-15, when demand in neighboring ERCOT reaches only 69% of its peak. For most regions on their peak-containing day, demand in neighboring regions is ~85%–90% of its regional peak.

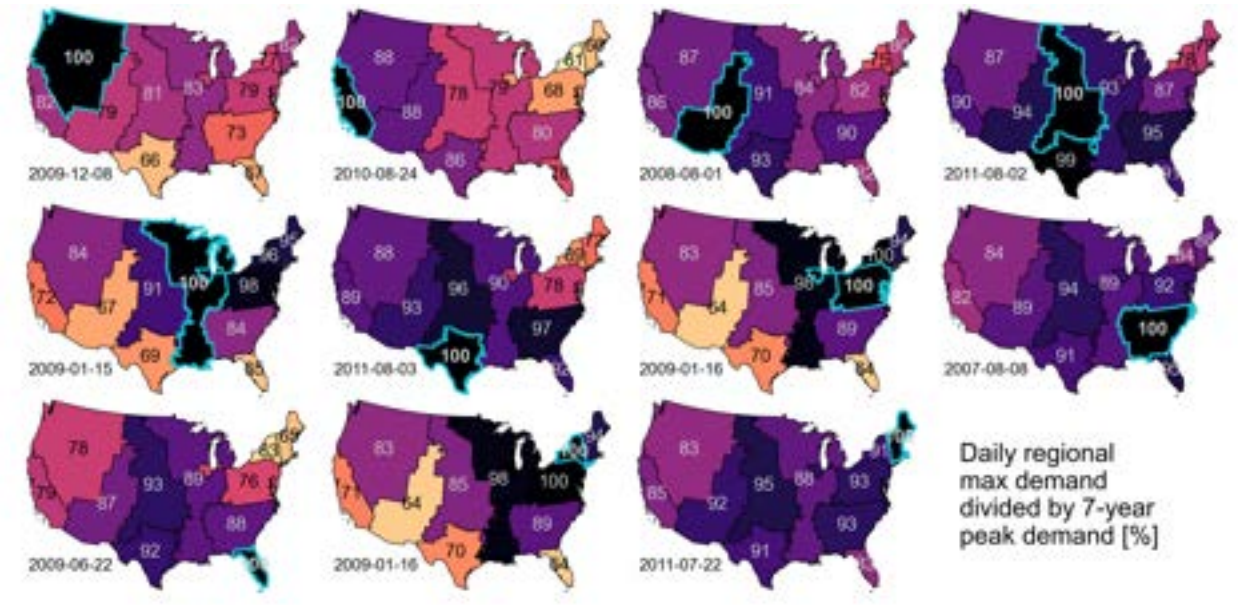



Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

*For each map, the focused planning region is outlined in blue, the date of the peak demand day in that region is given in the lower left, and the values and colors in each region represent the relative regional peak demand (normalized to the total regional peak demand across all 7 weather years) on that date. For example, 2009-12-08 is the peak demand day for NorthernGrid over 2007–2013; on that day, CAISO demand reaches 82% of peak CAISO demand over 2007–2013. Demand data are from the Mid-Demand assumption for 2050.*

### *Bidirectional power flows between regions support resource adequacy*

Within the PRAS model, transmission is used only to avoid dropping load; PRAS does not consider variations in marginal cost between generation technologies. Transmission flows in PRAS thus illuminate the use of transmission specifically related to grid reliability when local generation alone does not meet RA needs.

A diversity of usage patterns is observed in the PRAS model results for interregional transmission in the accelerated transmission frameworks (Figure 39). Hourly flow patterns are presented in Appendix D.3. Some interfaces in the P2P framework are used almost entirely unidirectionally: for the SPP→SERTP, MISO→FRCC, and MISO→PJM interfaces, 99.9+% of RA flows are in the indicated direction on a megawatt-hour (MWh) basis. Others are bidirectional: For the MISO→ERCOT, NYISO→ISONE, ERCOT→WestConnect, MISO→SPP, and CAISO→NorthernGrid interfaces, the distribution of RA flows between the two directions is between 50/50 and 60/40, with the arrow denoting the predominate flow direction. For the SPP→PJM interface, the large majority (98%) of RA flows are from wind-rich SPP to demand centers in PJM, but ~900 hours in the 7-year weather sample have energy flows from PJM to SPP to help SPP meet its RA needs. This observation mirrors the examples shown in Figure 35 and Figure 36, where high-renewable-resource regions can still be aided by neighbors on locally poor resource days.

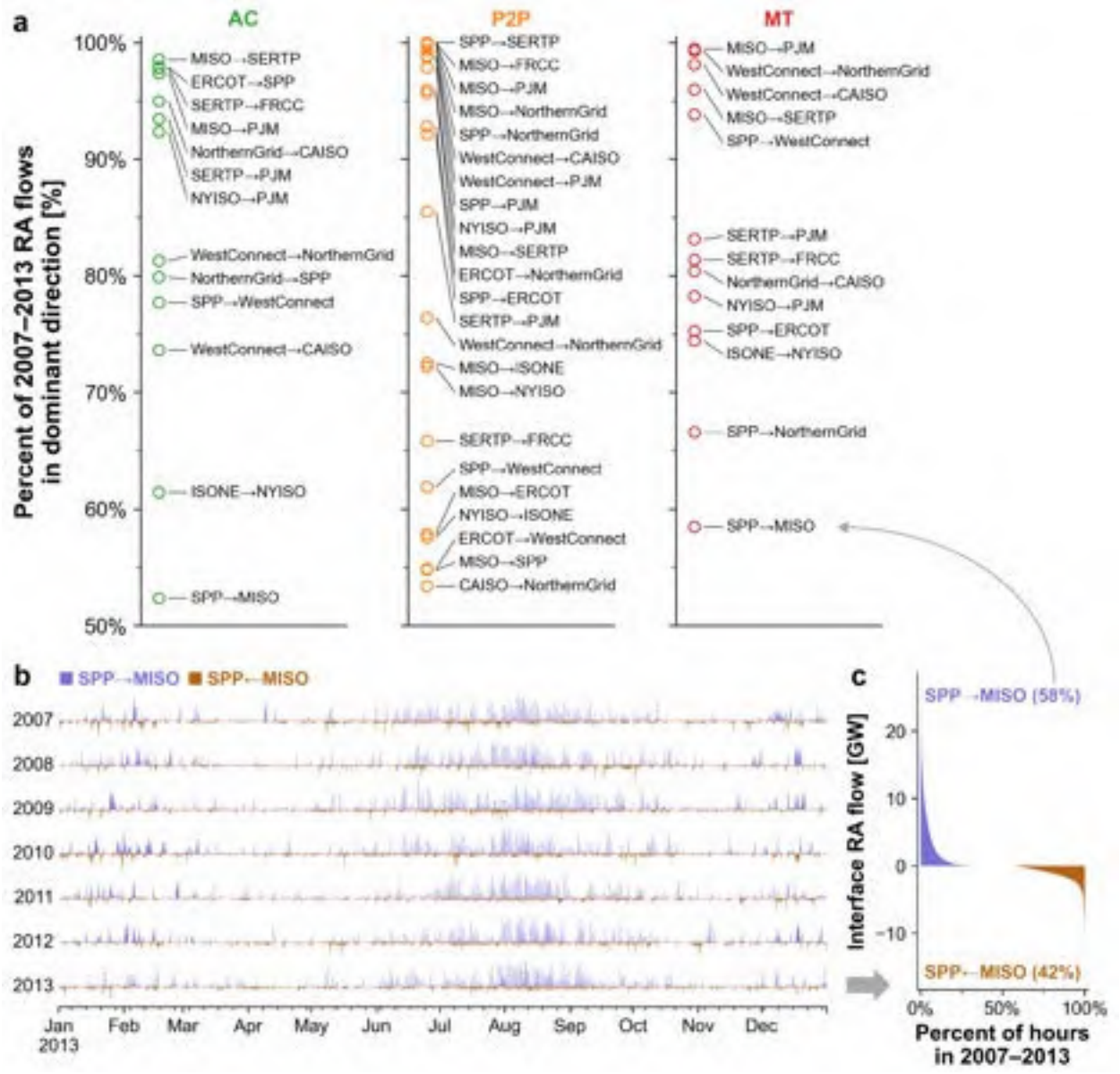



Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

*For each interface between planning regions (Figure 1c), the dominant direction is determined by the fraction of total hourly flow modeled in PRAS on a MWh basis over the 7 weather years spanning 2007–2013, and the percent of total flow in the dominant direction for each interface is shown in panel (a). Illustrative hourly flows and the sorted distribution of flows for the SPP→MISO interface in the MT framework are shown in (b) and (c), respectively.*

### *Interregional resource adequacy coordination reduces the cost of meeting resource adequacy requirements*

Because ReEDS co-optimizes the deployment and operation of generation and transmission to meet demand in both representative and outlying periods at least cost, it is difficult to disentangle the “energy value” and “RA value” (or “capacity value”) of interzonal transmission investments within a single ReEDS scenario.

To isolate the effects of interregional coordination of RA planning (or "RA sharing") on system cost and transmission deployment, two scenarios are compared: the "core" scenario using default assumptions and the "No RA sharing" sensitivity case where transmission flows are not allowed between planning subregions (Figure 1b) to meet RA needs. In effect, this sensitivity case requires each planning subregion to meet its RA needs solely from resources within its own borders rather than rely on interregional transmission and excess resource availability from neighbors.

Total costs through 2050 are notably higher in the "No RA sharing" case than in the "core" scenario that allows regions to coordinate to meet RA needs—roughly $200 billion higher in the Limited, AC, and P2P transmission frameworks and ~$380 billion higher in the MT framework (Figure 40a). Substantial savings could accrue from using existing interregional transmission for RA sharing, as evidenced by the large savings in the Limited transmission framework where new interregional transmission additions are not allowed.

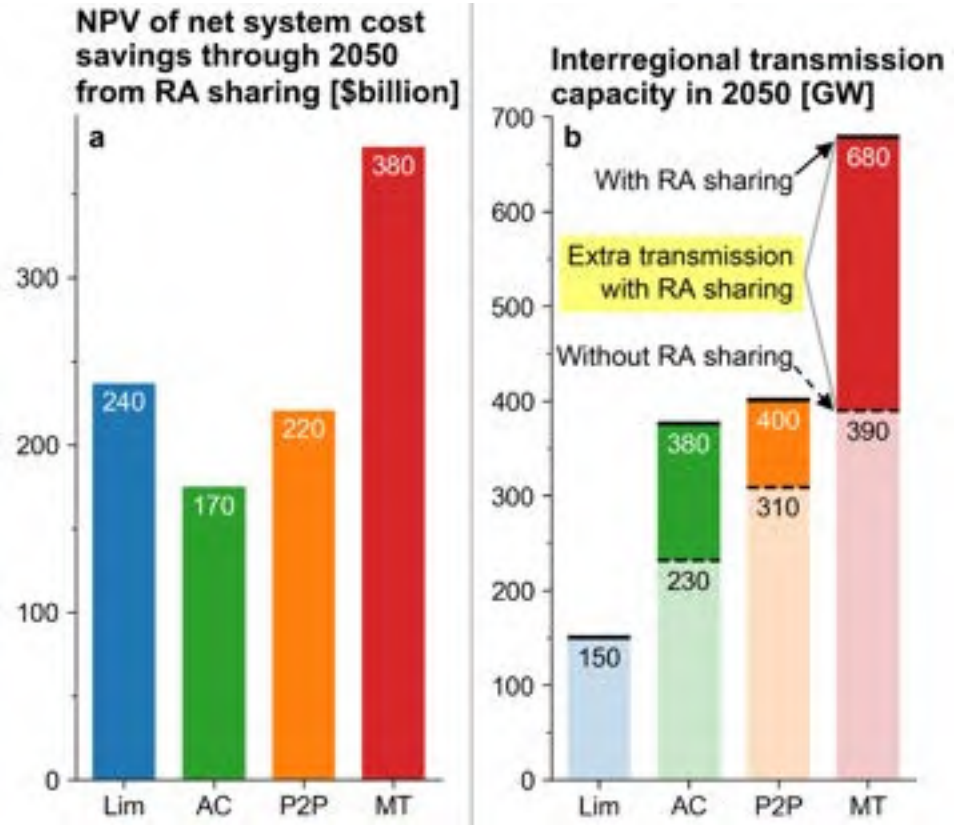



Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

*System cost savings (as shown in panel (a)) for each of the demand and emissions assumptions shown in Figure 3 are provided in Figure D-17.*

### *Significant amounts of interregional transmission are built primarily to serve resource adequacy needs*

The ability to use interregional transmission to meet RA needs also leads to substantial additions of new interregional transmission in scenarios that allow it (Figure 40b and Figure 41). Cost-minimizing interregional transmission capacity additions drop by ~40%–60% across the three accelerated transmission frameworks if RA sharing is not allowed, contributing to the ~$200–350 billion higher system cost compared to when RA sharing is allowed. Large interregional transmission additions in the upper Midwest drop out of the optimal solution if RA sharing is not allowed, highlighting the significant value of transmission during scarce but high-consequence periods of system stress and aligning with recent studies exploring the contribution of short-duration electricity price spikes to long-distance transmission value (Millstein et al. 2022).

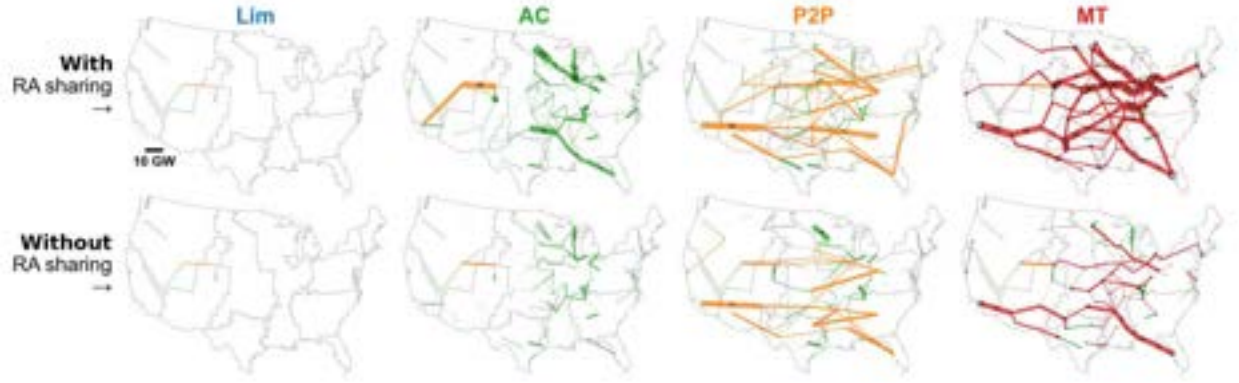



Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

# Conclusions

This chapter documents the methods, assumptions, scenario design, and results from the zonal capacity expansion, resource adequacy, and transmission value analyses of the NTP Study. The analysis is designed to assess the role of transmission in the future U.S. electricity system. It compares how different transmission frameworks—ranging from those where transmission expansion is limited to futures with highly coordinated transmission planning and development with advanced technologies—might impact this role. The analysis includes 96 scenarios that capture a broad range of possible market, policy, and technology uncertainties.

Overall, the analysis finds that accelerating transmission expansion enables decarbonization of the U.S. power system at lowest cost by enabling the interconnection and delivery of large amounts of inexpensive wind and solar energy—and other low-emissions resources—to all electricity consumers and to support resource adequacy.

Under Current Policies scenarios—which do not apply a limit on national emissions—accelerating transmission expansion can lead to cumulative $CO_2$ emissions reductions of 10.2–11.2 billion metric tons (43%–48%). With a limit on national $CO_2$ emissions, the benefits of transmission expansion are expressed through lower total system costs. These benefits increase with more rapid grid decarbonization and greater electrification. With the core central decarbonization assumptions, which include 90% emissions reductions by 2035 and Mid-Demand growth (2.0%/year), accelerated transmission expansion saves $270–490 billion in electricity system expenditures through 2050. The system cost savings outweigh expenditures for transmission, resulting in high transmission benefit-cost ratios (above 1.5) for all scenarios and sensitivity cases.

Significant amounts of transmission are added in the decarbonized systems modeled. In the central decarbonization scenarios, total U.S. transmission grows to 2.4–3.5 times the size of the 2020 grid by 2050 across the accelerated transmission frameworks; the amount of growth scales with decarbonization rate and demand growth. Transmission expansion occurs at all scales, including local interconnections for new wind and solar, longer-distance interregional transmission, and, when allowed, seam-crossing transmission that increases the transfer capacities between the Western, Eastern, and Texas interconnections. Scenarios that consider HVDC additions result in greater total regional and interregional transmission expansions and yield the largest economic benefits.

Transmission is added in all regions of the country, but the highest concentration is developed in the central wind belt. This geographic distribution of transmission development is robust across the sensitivity cases modeled. The amount and location of interregional transmission expansion between subregional pairs by 2035 is identified based on the full suite of sensitivity cases and referred to as High Opportunity Transmission (HOT) interfaces. Further study is needed to identify potential transmission projects that align with the subregional HOT interfaces.

Resource adequacy is considered in the development of all the scenarios modeled to ensure RA needs are met in decarbonized systems, including those with significant transmission expansion and much greater reliance on remote and variable resources. A variety of technologies contributes to meeting adequacy needs. Transmission can support RA by enabling the sharing of resources and increasing geospatial diversity of load and VRE, especially with interregional transmission over spatial scales larger than weather systems. Without interregional RA coordination to take advantage of transmission's capabilities to support RA, total system costs to decarbonize are estimated to increase significantly and less transmission development occurs. In other words, RA is an important source of value for transmission in the future.

These findings demonstrate how accelerating transmission expansion can support a lower-cost transition toward energy system decarbonization while maintaining reliability. However, the complexities of transmission planning require higher-fidelity analysis to increase confidence in these results. For example, this chapter examines resource adequacy for the scenarios, but operational reliability and resiliency are not analyzed. The scenario analysis presented in this chapter provides the starting point for further study. Subsequent chapters present the production cost, power flow, and other detailed analysis for a subset of—and variations to—the scenarios described in this chapter.

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# Appendix A. Regional Energy Deployment System (ReEDS) Model

The National Renewable Energy Laboratory (NREL) ReEDS model is a capacity expansion model for the contiguous United States electricity system. ReEDS co-optimizes generation, storage, and transmission to find the systemwide least-cost portfolio that meets demand, grid reliability, and policy requirements. For this study, ReEDS starts in 2020 and optimizes each 5-year solve period sequentially through 2050. The ReEDS documentation (Ho et al. forthcoming) and latest NREL Standard Scenarios report (Gagnon et al. 2024) provide further details about the model. The model is open source and can be accessed at https://www.nrel.gov/analysis/reeds/. Earlier versions of ReEDS have been used in several transmission, grid integration, and policy and scenario studies, such as the North American Renewable Integration Study (Brinkman et al. 2021), Denholm et al. (2022), and the Electrification Futures Study (C. Murphy et al. 2021).

This appendix highlights newer capabilities in ReEDS that are relevant to the NTP Study.

## A.1 Transmission Modeling

This section describes multiple aspects of transmission modeling in ReEDS: 1) existing interface transfer limits for the zonal structure of the model, 2) prescribed transmission projects in the scenarios, 3) transmission cost assumptions, 4) high-voltage direct current (HVDC) specific assumptions and modeling, and 5) assumptions for the annual build limits applied in the Limited framework.

For generation and storage, the model is initialized using unit-level data from the EIA Annual Energy Outlook. The capacity for each of these units is associated with a generator or storage type and one of the 134 model zones.[39] Retirements and new capacity builds are primarily endogenously determined as part of the model's decision-making process.[40]

Initializing the current transmission capacity for the zonal model is more challenging because of the alternating current (AC) nature of power flow dictated by Kirchhoff's laws. In particular, the aggregate interface transfer limit between two zones cannot be simply approximated by the sum of thermal capacities of the lines crossing the zonal boundary. A better approximation for the interface limits uses a method documented in Brown et al. (2023), which applies a DC power flow approximation approach. The approach starts with a nodal transmission dataset and results in estimates for the maximum transfer capacities across all interfaces for the 134 model zones.

[39] Multiple vintages are also tracked particularly to reflect the range of heat rates for thermal generators.
[40] Recently installed (2021–2023) capacity and projects that are under final stages of deployment, as identified by EIA, are also prescribed for development in the model across all scenarios. Similarly, announced plant retirements from EIA are also modeled.

For most interfaces, the method assumes all lines are available when estimating the interface transfer limits. However, for interregional interfaces—interfaces between zones in different transmission planning subregions, e.g., between SPP-North and MISO-North—a more conservative approach where the single largest line crossing the interface is assumed to be unavailable, reducing the maximum transfer limits between such zones, is applied. This approach serves as a proxy for the transfer capacity between planning subregions accounting for N-1 contingencies. One MW of new transmission between two zones adds one MW of transfer capability between the zones (no derate), but the sum of new transmission crossing between transmission planning subregions is derated by 15% for the determination of maximum interregional flows (so if 100 MW of new transmission capacity is added across interfaces between SPP-North and MISO-North, the transfer capability between SPP-North and MISO-North is increased by 85 MW) as a linear approximation of security constraints.

The ~65,000-bus North American Renewable Integration Study (NARIS) database (Brinkman et al. 2021) represents expected transmission capacity for 2024 and is used to estimate currently installed transmission in ReEDS. ReEDS begins installing new, currently unplanned transmission in the 2030 solve year to minimize total system cost. Select transmission projects that are under construction but not yet completed are prescribed to be built in the model during the 2030 solve period.[41]

In addition to the existing transfer capacity and prescribed transmission projects, ReEDS can decide to build new transmission capacity as part of its co-optimization framework. The cost for new transmission is based on cost estimates from Western Electricity Coordinating Council (WECC) (Western Electricity Coordinating Council 2019), MISO (MISO 2021), Southern California Edison (Southern California Edison 2021), and a representative southeast utility. Transmission cost estimates also account for terrain, land type, and other siting factors included in the Renewable Energy Potential (reV) model (Lopez et al. 2024).[42] For interzonal transmission, distances between model zones are estimated based on a least-cost path method between the largest load centers in the zones. These distances are longer than the straight-line paths between the load centers. For interzonal AC transmission, assumed costs are based on new greenfield 500-kilovolt (kV) (1500-MW) single-circuit lines (Western Electricity Coordinating Council 2019). Figure A-1 shows the resulting interzonal AC transmission capital costs that result from this process. Annual transmission fixed O&M costs are assumed to be 1.5% of the upfront capital costs per year (European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014).

[41] Prescribed transmission projects in the scenarios include Colorado Power Pathway (3,274 MW), TransWest Express (3,000 MW), Greenlink Nevada (2,000 MW), and Boardman to Hemingway (1,732 MW). Several other transmission projects, some announced after the analysis was completed, are at various stages of development. Their exclusion does not imply any judgment about their viability.
[42] https://github.com/NREL/reV

The same approach for estimating transmission costs is used to estimate interconnection costs for new wind and solar capacity (see Section A.2) but with lower voltages and associated higher costs on a per MW-mile basis.

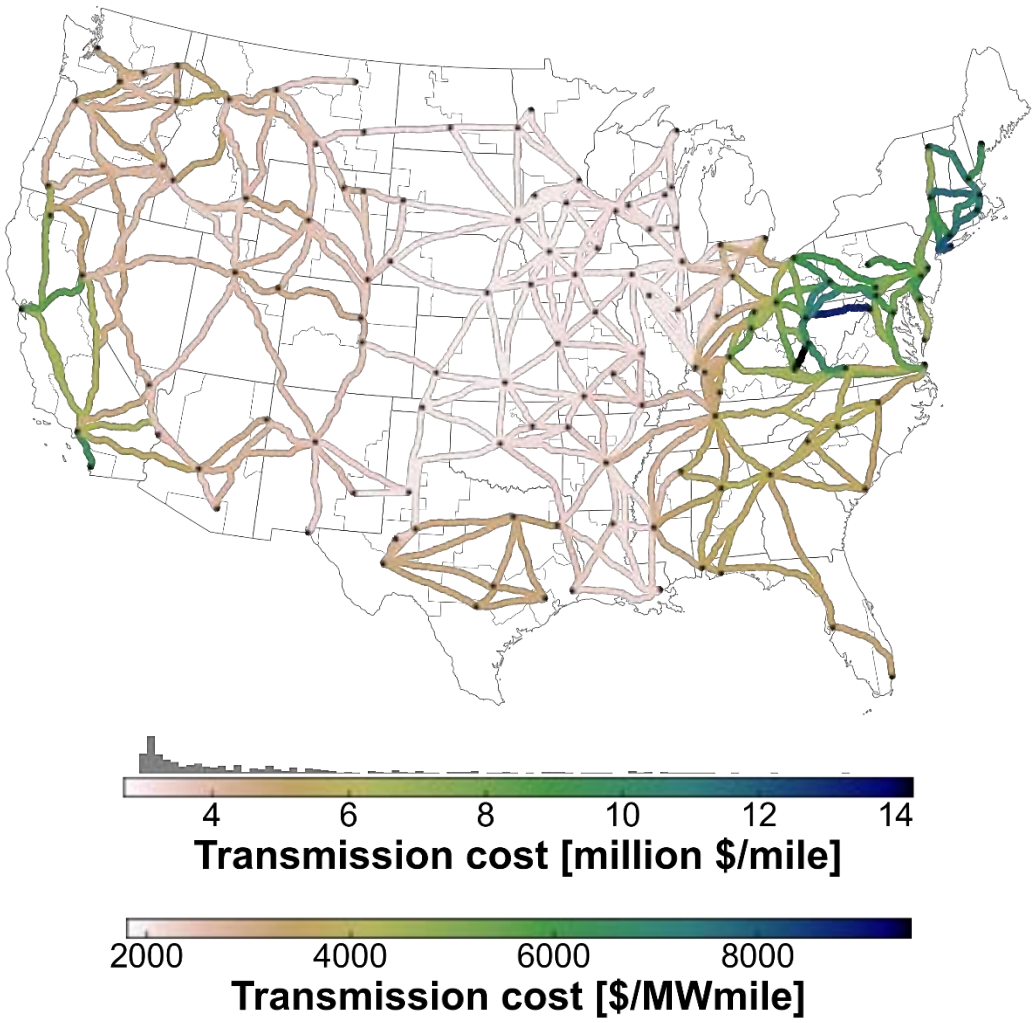



Figure A-1. Interzonal AC transmission cost assumptions

Direct current (DC) transmission line costs are assumed to be approximately 60% less than the $/MW-mile costs shown in Figure A-1 for AC transmission based on the MISO cost estimation guide (MISO 2021). However, DC transmission has the added cost of the converter stations. These are assumed to be $140/kW for line-commutated converters (LCCs) and back-to-back (B2B) interties and $180/kW for voltage source converters (VSC), also based on MISO (MISO 2021).

For the multiterminal (MT) framework, HVDC connection options are the same as those shown in Figure A-1 for AC transmission. For point-to-point (P2P), a new set of long-distance 195 candidate connections is included (Figure 2c). These are identified based on the highest wind resource and load centers in each region. Distances between these points are also based on the least-cost path estimation method.

Transmission losses are approximated based on distances between the zone "centers" (taken as the largest urban center when available, or a large transmission substation for zones without urban areas). Line losses are assumed to be 1% per 100 miles for AC transmission and 0.5% per 100 miles for DC. Losses are also modeled for the AC to DC conversion with 0.7% losses assumed for LCC technologies (used in the P2P framework) and 1.0% for VSC (used in the MT framework) (Alassi et al. 2019).

As a linear model, ReEDS considers continuous amounts of transmission capacity—with transmission costs in units of dollars per MW-mile—rather than discrete transmission circuits or projects. This simplification can lead to unrealistically sized transmission lines, particularly for HVDC transmission under the P2P and MT frameworks. To partially mitigate this, the analysis applies an iterative approach with two model runs for each of the scenarios under the HVDC (P2P and MT) frameworks. The first run uses all possible candidates. During the second, HVDC connections for which ReEDS builds less than 1.5 GW of capacity by 2050 are excluded.[43] This approach does not preclude small capacities but greatly reduces their number. ReEDS does not comprehensively account for additional upgrades or reinforcements for expansion of high-voltage DC or AC lines—e.g., that may be necessary to address voltage or stability issues—but estimated network reinforcement costs are included for new wind and solar development (see next section).

Under the Limited framework, a constraint is applied to the annual rate of transmission deployment. This rate is based on the maximum amount of transmission build in the United States over the past 10 years (2014–2023). Data from Federal Energy Regulatory Commission (FERC) collected by Lawrence Berkeley National Laboratory (LBNL) (Wiser et al. 2023) are used to estimate this maximum. The historical transmission data are reported by voltage and miles. To use this in ReEDS requires converting the voltage into capacity, and the following simple conversion factors are assumed: 400 MW for ≤230 kV, 750 MW for 345 kV, and 1500 MW for 500 kV. This approach results in 1.83 TW-mile/year of maximum annual transmission builds.

## A.2 Wind and Solar Supply Curves

Assumptions for wind and solar developable potential, resource quality, and transmission access used in ReEDS are developed from the reV model (Maclaurin et al. 2021). reV is a high-resolution geospatial tool that considers renewable resources, land availability, hourly generation profiles, and transmission interconnection costs for approximately 60,000 potential sites across the contiguous United States. The most recent results and assumptions of the reV analysis for land-based wind and utility-scale solar photovoltaics (PV)[44] are documented by Lopez et al. (2024) and summarized below.

The technical resource potential for wind and solar is affected by the available land that could be developed. Land availability is estimated by considering siting suitability and

[43] For the scenarios translated for nodal modeling (Chapter 3), this iteration is also applied in 2035 instead of 2050 because the nodal modeling is conducted for 2035 systems.
[44] reV is also used similarly for offshore wind and concentrating solar power.

spatial exclusions from other uses. These siting considerations include terrain (e.g., slope, elevation), airspace and defense (e.g., airports, radar), environmental factors (e.g., endangered species habitat, wetlands, national parks and conservation areas), and siting regulations (e.g., setbacks from existing structures, roads, railroads, transmission lines, and pipelines). Default exclusion assumptions used for nearly all scenarios are based on the "Reference Access" case (Lopez et al. 2024). Under these assumptions, the total developable areas for wind and PV across the contiguous United States are 1.9 million square kilometers ($km^2$) and 2.6 million $km^2$, respectively. These land areas correspond to a technical potential of 11 TW of capacity potential for wind and 112 TW for PV; the higher PV potential is because of the relatively lower total land use requirements.[45] The developable potential for these resources is not spatially uniform with generally lower resource potential in locations with higher populations and associated built environment. Figure A-2a,c shows maps of the assumed resource potential for wind and solar, respectively, under the default assumptions. This available potential represents *options* that ReEDS could choose to deploy based on its optimization framework, which is much larger than the resulting buildout in the scenarios. ReEDS aggregates these available sites into its 134-zone structure but includes additional resource classes and transmission cost bins (Ho et al. forthcoming).

To capture the uncertainty associated with renewable energy siting over the next 3 decades, a Siting Limited sensitivity (Section 2.3.5) is included. For the Siting Limited sensitivity, the "Limited Access" siting regimes from Lopez et al. (2024) replace the Reference Access assumptions. Limited Access has more stringent exclusions, such as greater environmental exclusions and much larger setbacks that represent social challenges with siting. In this case, the developable area (and capacity) for wind is reduced to 800,000 $km^2$ (5.9 TW) and to 1.4 million $km^2$ (58 TW) for PV. As shown by Figure A-2b,d, the available resources are even more concentrated in the central regions of the country with lower population densities.

[45] The disturbed land area for these technologies differs, with <5% of the area of wind plants from roads, pads, and other infrastructure whereas approximately 90% of the area is covered by solar panels and other infrastructure.

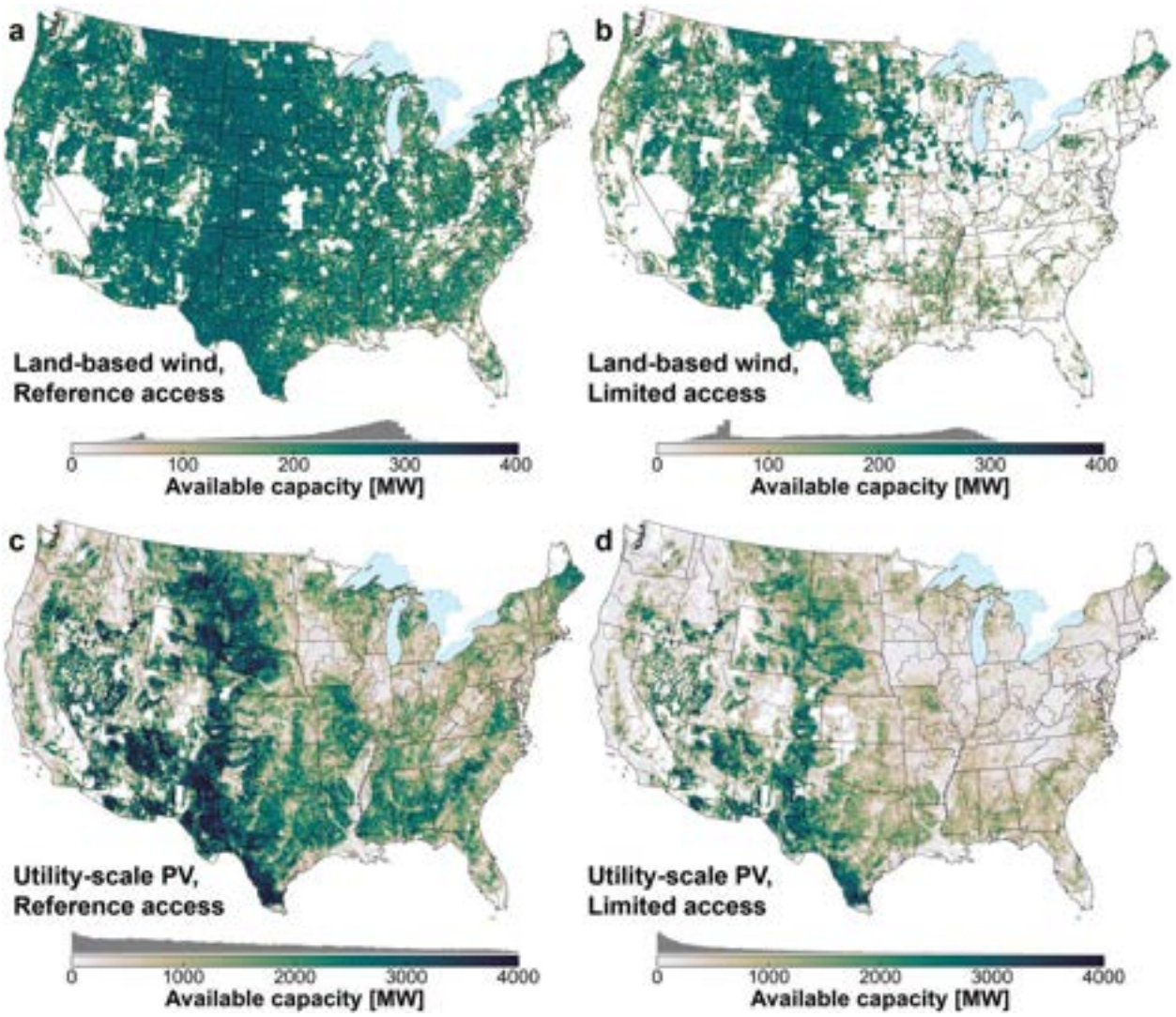



Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

*Histograms of available capacity by site are included above color bars. Note the difference in color scale limits between wind (a, b) and PV (c, d).*

In addition to the developable potential, reV also estimates the performance (capacity factor) and generation profiles for each of the ~60,000 sites. Generation is modeled using the System Advisor Model[46] and based on meteorological data (e.g., wind speed, irradiance, temperature) from the 2-km resolution WIND Toolkit (Draxl et al. 2015) and 4-km resolution National Solar Radiation Database (Sengupta et al. 2018), including losses. Hourly generation is modeled for 7 weather years (2007–2013) for which coincident wind, solar, and demand data are available. The wind and solar technology assumptions are based on the Annual Technology Baseline (ATB) 2023 Moderate case for 2030.

[46] https://sam.nrel.gov/

Figure A-3 shows supply curves—the resource potential (in GW) ordered by lowest levelized cost of energy (LCOE)[47] in 2030—based on the land availability and performance assumptions from reV. The dashed lines show the supply curves without considering interconnection costs (Site LCOE). Interconnection costs as modeled in reV include spur lines to connect the renewable energy site to an existing substation that is the point of interconnection (POI), POI substation upgrade costs, and network reinforcements that represent other upgrades needed for the grid network. The underlying equipment costs and routing methods associated with these are based on the same sources used for interzonal transmission (Section A.1) but based on a wider range of voltages (Lopez et al. 2024). For network reinforcement costs, assumed per mile costs for upgrades are 50% of the cost of greenfield transmission and effective distance of upgrades based on the POI location and the largest load center in each of the 134 model zones (traced along the existing transmission system). This is a simplified approach to estimating interconnection costs but provides regionally varying costs that are approximately aligned with empirically observed costs (Seel et al. 2023). Figure A-3 shows how including interconnection costs (All-in LCOE, solid lines) is estimated to increase LCOEs by at least $5–$10/MWh for many locations. The modeling does not choose sites and technologies based on LCOE; LCOEs from Figure A-3 are shown to indicatively display the resource potential and quality assumed.

[47] ReEDS does not select resources based on LCOE. For example, options with higher LCOE can be chosen if their profiles are better aligned with system needs or the locations are preferred because of transmission congestion or for other reasons.

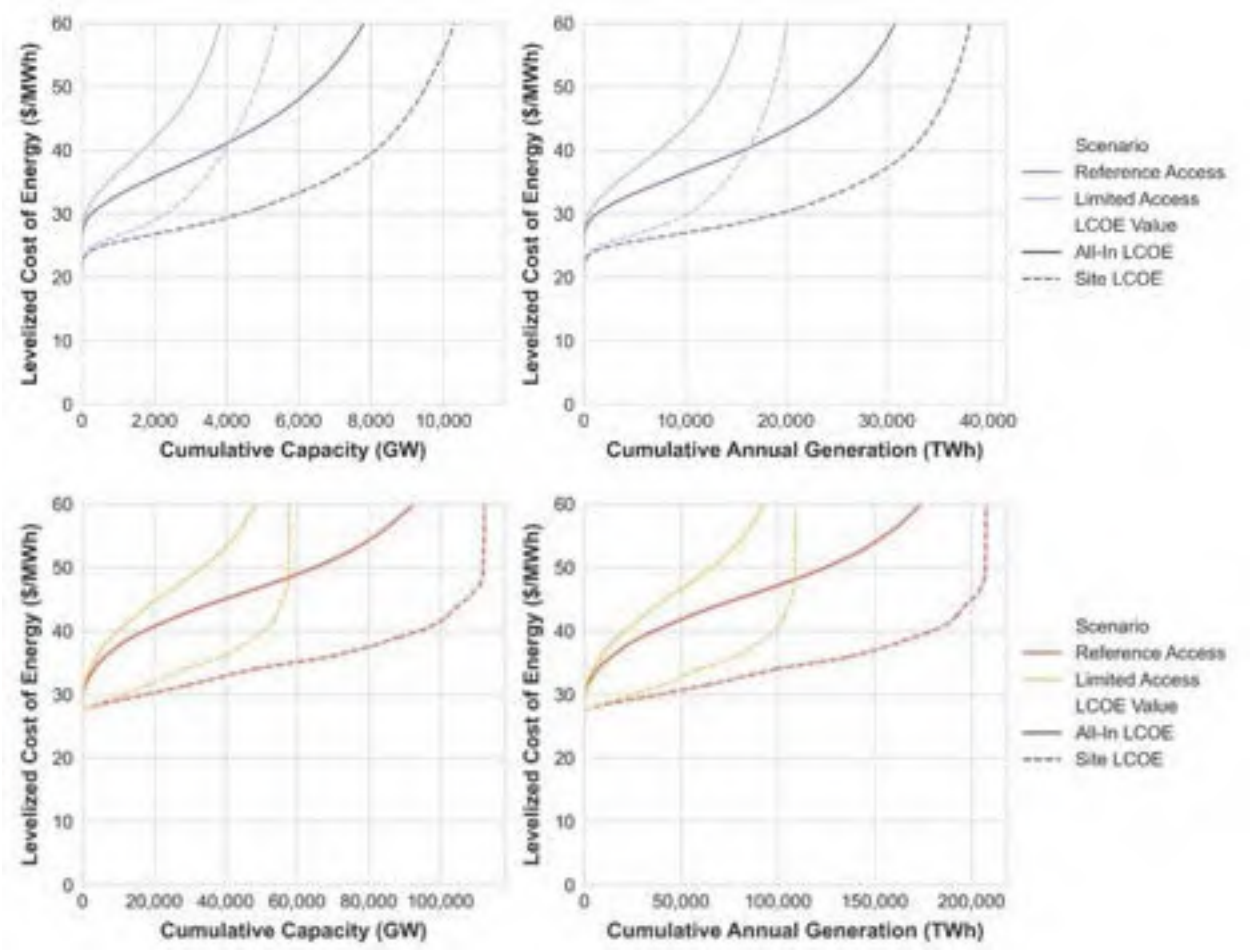



Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

*Source: Adapted from Lopez et al. (2024). LCOEs are based on 2030 technology assumptions. Values above $60/MWh are not shown. "Site" LCOE excludes interconnection costs. "All-in" LCOE includes interconnection costs.*

The interconnection costs modeled here are reflected in ReEDS, and these expenditures are tracked as local transmission investments. Local transmission distances and capacities—usually reported in MW-miles—also use the spur line distances and traced network upgrades.

## A.3 Hydrogen Modeling

Hydrogen production and use for grid applications is endogenously modeled in ReEDS for the NTP Study. In other words, capacity for electrolyzers, hydrogen storage, and hydrogen-fueled generation are all decisions made by the model considering their assumed costs and constraints. For the NTP Study scenarios, hydrogen production is modeled via electrolysis only; steam methane reforming with or without carbon capture and storage (CCS) is not considered. In the default scenarios, electrolyzer costs are assumed to decline from $1,750/kW in 2022 to $550/kW in 2030 and remain constant after 2030 (DOE 2023b). In the Electrolyzer Low Cost sensitivity, electrolyzer costs decline to $157/kW by 2050 (DOE 2023b).

The model includes the electricity demand needed for electrolysis, which increases overall demand beyond the level shown in Figure 5 and Figure 6. Two forms of geological hydrogen storage—salt caverns and hard rock formations—are included as well as the ability to construct storage in underground pipe systems. Data on the availability of geological storage are taken from Lord et al. (2014) (Lord, Kobos, and Borns 2014). Costs for all three storage options are based on Papadias and Ahluwalia (2021) (Papadias and Ahluwalia 2021) and are approximately $40/kilogram of hydrogen (kg-$H_2$) for salt caverns, $65/kg-$H_2$ for hard rock, and $590/kg-$H_2$ for underground pipes. Electricity generation based on hydrogen is modeled to be from combustion turbines (CTs). These can be new greenfield $H_2$-CTs or can be retrofitted from existing natural gas (NG) power plants. The cost of greenfield $H_2$-CTs is assumed to be the same as that of new NG-CTs except with a 3% cost increase to account for adding a clutch to enable the CT to operate as a synchronous condenser (Denholm et al. 2022). Upgrades from NG-CT to $H_2$-CT are assumed to be 33% of the cost of a new plant, and upgrades from natural gas combined cycle (NG-CC) to $H_2$-CT are assumed to be 55% of the cost of a new plant because of the need to upgrade the steam turbine as well. Heat rates are assumed to be the same between $H_2$-CTs and NG-CTs.

Hydrogen storage levels are tracked chronologically over the modeled weather year at daily resolution within each model zone. In this way, the modeled hydrogen option is representative of seasonal storage and serves the primary purpose of supporting resource adequacy in the scenarios. Transport of hydrogen between zones is not allowed. Future work is needed to assess the relative trade-offs between hydrogen and electricity transmission. In addition, the scenarios do not include the use of hydrogen outside of the electricity sector, e.g., for use in industry and transportation. And, as noted in Section 2.3.2, hydrogen tax credits are not included in this study because the final policy was not released when the analysis was completed.

## A.4 End-Use Emissions

The three electricity demand cases (Low, Mid, High) are based on different levels of electrification and associated reductions in end-use emissions as described in Section 2.3.3. Figure A-4 shows how direct emissions from the end-use sectors (e.g., vehicle tailpipe emissions for transportation, emissions from natural gas combustion in furnaces and water heaters in buildings, and emissions from heating and other processes in industry) vary across these cases. The power sector emissions results from ReEDS can be combined with these to estimate total energy emissions in the United States; however, care is needed to account for emissions from indirect electrification because consumption of hydrogen outside the power sector is not included.

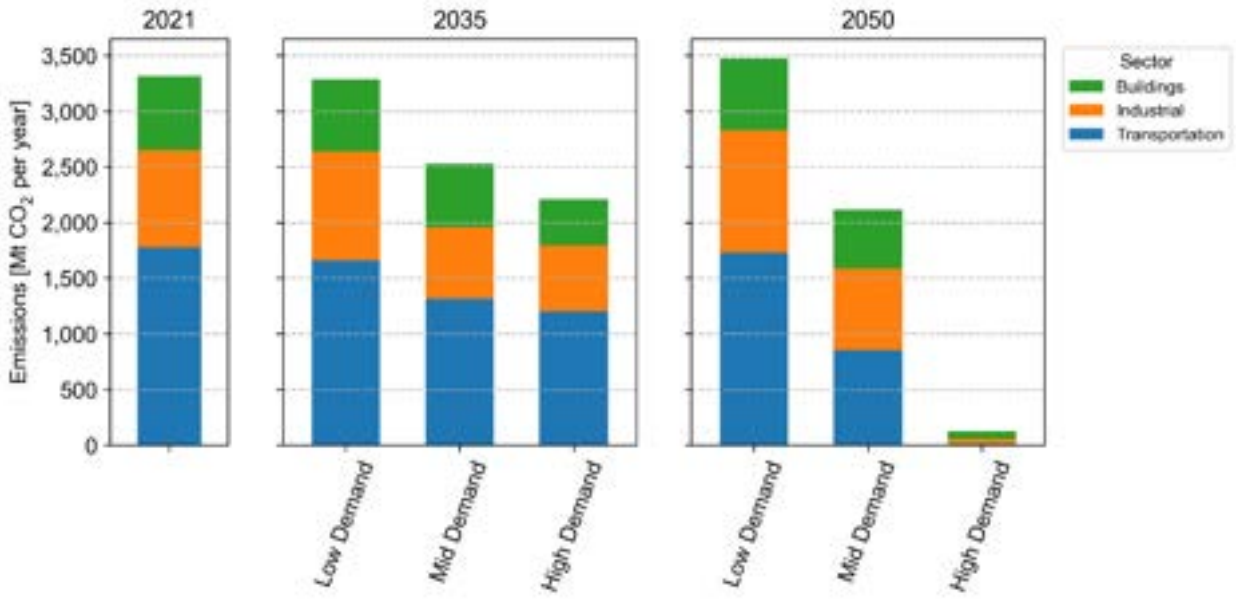



Figure A-4. End-use emissions for the three electricity demand cases

## A.5 Climate Change Sensitivity

By default, ReEDS uses historical weather data for load and VRE generation profiles. Because future weather—and associated electricity demand patterns and generation performance—will likely differ from historical weather, a "Climate Change" case with a different set of assumptions is included as a sensitivity.

For this sensitivity, climate-change-impacted load and generation profiles were created from Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC) (Buster et al. 2023). The Sup3rCC data are based on global climate model (GCM) data and use generative machine learning models to represent realistic spatiotemporal variability in wind, solar, and load profiles at a nominal 4-km hourly resolution. The Sup3rCC data used in this project are based on the climate model MRI-ESM-2.0 for the SSP5 Climate Change scenario with a climate forcing of 8.5 W/m$^2$ (Yukimoto et al. 2019). The projected weather data for 7 years (2050–2056) from this scenario are applied to all model years.[48]

Wind and solar PV generation profiles are created using the reV model with the Sup3rCC weather inputs and the same technology assumptions as used in ReEDS (Lopez et al. 2024). The climate-impacted load profiles are created using regression models that establish a relationship between state-level subsector loads (e.g., residential cooling loads for Colorado) and population-weighted hourly meteorological variables (e.g., air temperature, humidity, and irradiance). The regression models were trained on meteorological years 2007–2012 and validated in 2013. The validation results show low bias error, including during peak load hours, and demonstrate the

[48] In other words, the weather forecasted for 2050–2056 is applied to load, wind, and solar PV generation in all model years from 2020 to 2050. This is justified given the long-lived nature of most power system assets and the uncertainties with long-term load forecasts.

models' ability to extrapolate peak loads with nonhistorical temperature inputs (necessary to explore the impacts of climate change on high-stress events).

The climate-impacted load data show an increase in spring and fall demand during high-load periods, especially in the Southeast and the Pacific Northwest because of more frequent and intense heat events (Figure A-5). Summer peak loads generally increase within a state by 2%–8% in magnitude although there is significant spatial variability with some states exhibiting small decreases in load whereas others exhibit increases of up to 14%. Winter peak loads are highly dependent on weather year and region with most states in the East exhibiting a decrease in peak load and other states in the West exhibiting a slight increase in peak load. Because of the local nature of weather events that drive peak load events, the change in coincident peak load tends to decrease with larger spatial aggregations. For example, the coincident peak load across the contiguous United States increases only by 2%. The changes in peak load discussed here are based on isolated effects of weather. Load from both historical and future weather in these comparisons is based on end-use sector (i.e., electrification) assumptions from the 2050 model year in the High-Demand scenario. The impact of climate change on demand profiles is typically smaller in earlier years and for the lower electrification scenarios.

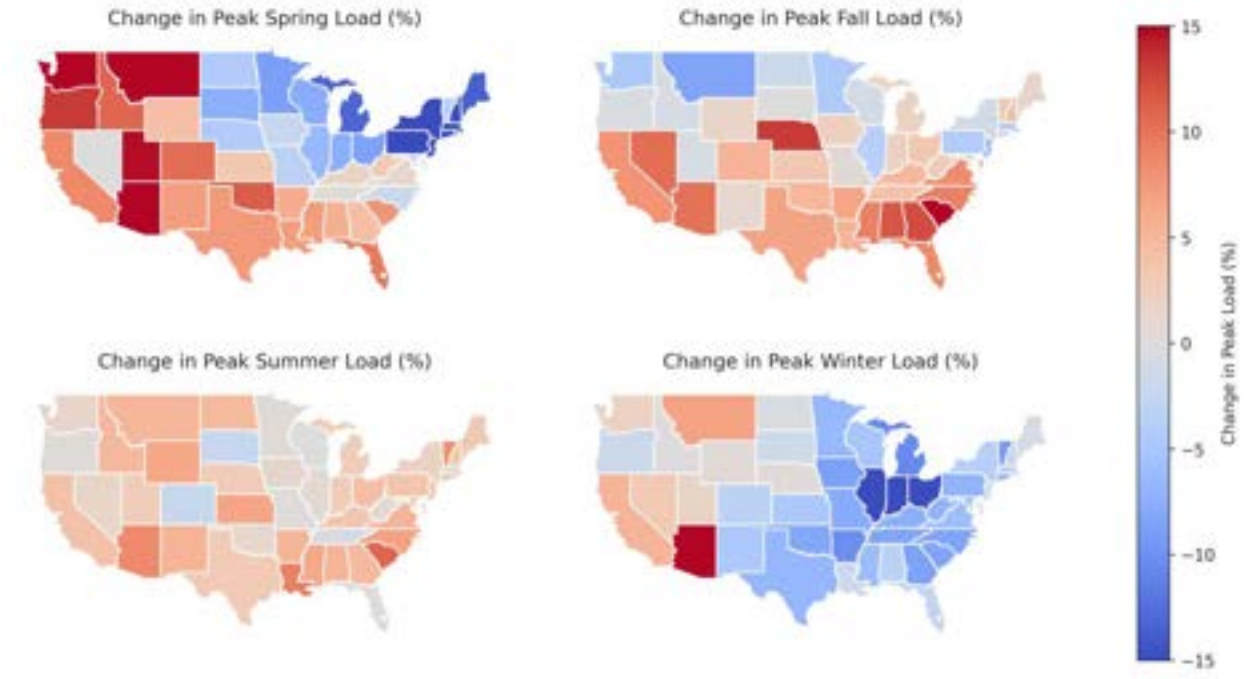



Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

*The differences are based on the maximum hourly demand for each season across all 7 future weather years relative to the maximum during the 7 historical-weather-year period. This comparison is for the High-Demand case for the 2050 model year, which includes significant electrification.*

The climate model and scenario used here do not project significant changes in renewable energy generation. Other GCMs have found larger changes to wind resources that could impact net load profiles and outcomes modeled (Martinez and Iglesias 2022). The Sup3rCC data used here are based on only 7 years (2050–2056) from a single climate model. Additional weather years would better represent the uncertainty from interannual variability. Alternative GCMs and scenarios would also yield different outcomes. Finally, because Sup3rCC is based on GCM data, it does not represent many important meteorological phenomena such as wildfires and hurricanes. Future work will study uncertainty from additional weather years, GCMs, and climate scenarios.

In addition to changes to demand, wind, and solar generation, the Climate Change sensitivity also includes adjustments to the potential contribution of hydropower, thermal resources, and transmission. Specifically, simple derate factors are applied to the summer capacity of these resources during both “representative” and “stress” periods modeled in ReEDS to represent various phenomena that could reduce the performance of these technologies or to reduce planners’ confidence in these resources for meeting system adequacy requirements.

To represent potential climate change impacts on hydropower resources, reservoir hydropower capacity is reduced by 20% during the modeled stress periods. This 20% reduction is applied for the 2050 model year with a simple linear ramp to this ultimate value starting in 2025. Derates are applied uniformly in all regions. The 20% value approximates impacts estimated by Turner et al. (2022) for hydropower facilities in WECC.

To represent climate change impacts on thermal cooling units, all available thermal generation capacity is derated during summer periods by 15% in 2050 with the same linear ramp starting from 2025. For thermal power plants, ReEDS uses summer capacity ratings, as reported for the EIA National Energy Modeling Systems data and supplemented with EIA form-860 data, for all nonwinter seasons. Summer capacity ratings are typically lower than winter or nameplate capacities, and the derate applied here is on top of this reduction as a proxy for higher temperatures and lower cooling water availability compared to historical summer periods.[49] This value is based on a 15% reduction in WECC thermal capacity driven by cooling water availability (Voisin et al. 2017). In addition, data from Electric Reliability Council of Texas (ERCOT) imply an 11% reduction in thermal capacity during summer (Electric Reliability Council of Texas 2022).

To represent climate change impacts on transmission, summer transmission capacity is derated by 5% by 2050 using a linear ramp starting from 2025. In ReEDS the transmission capacities are already based on summer ratings, so this reduction would be incremental to those driven by higher-than-historical temperatures during summer.

[49] Winter capacities are used for winter periods in ReEDS. All reported capacities in this study reflect summer ratings.

The 5% value is within the range estimated by Bartos et al. (2016). Another study for California suggests a 7% reduction (Sathaye et al. 2011).

Climate change impacts on demand, generation resources, and transmission are complex with significant uncertainties. Given the simple representation and proxy assumptions applied here, the results from the climate change sensitivity cases should be interpreted as indicative rather than definitive.

# Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling

The Regional Energy Deployment System (ReEDS) and Probabilistic Resource Adequacy Suite (PRAS) models are operated in concert to analyze the scenarios presented in this chapter. Both models are summarized in Section 2.1. Appendix A provides more details about ReEDS; this appendix provides additional detail about PRAS and discusses how the models are integrated to help ensure the future portfolios analyzed are resource adequate. Mai et al. (forthcoming) provide further explanation about the combined modeling. Documentation for an earlier version of the PRAS model can be found in Stephen (2021), and the model is available open source.[50]

## B.1 What Is PRAS?

PRAS is a probabilistic tool that simulates thermal generator outages and economic dispatch over a multiyear period to generate adequacy metrics for power system portfolios. It covers the same geographic extent (contiguous United States) with the same zonal spatial resolution (134 zones) as ReEDS. As described next, most of the data used in PRAS are passed directly from ReEDS. For example, hourly wind, solar, and load profiles are the same as those used in ReEDS. For this analysis, PRAS executes hourly simulations over 7 weather years (2007–2013).

PRAS models transmission in the same zonal manner as ReEDS and does not represent transmission outages. For thermal generators, the total capacity in each zone is disaggregated into individual units to facilitate the Monte Carlo assessment performed by PRAS. This disaggregation process uses data for existing units from the EIA National Energy Modeling System (NEMS) model (EIA 2023b) and, for new capacity, typical unit sizes from the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023). Outage rates for thermal generators and storage are based on 2014–2018 data from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) (NERC 2023b).

By using multiple years of hourly renewable energy and load possibilities along with thermal generator and storage outages, PRAS can provide statistical measures about the likelihood of unserved load. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This can be used to assess system adequacy as well as when and where the system is likely to be stressed.

## B.2 Integrated ReEDS-PRAS process

Figure B-1 shows how ReEDS and PRAS are used together. For a given solve period (e.g., 2035), ReEDS develops an initial system design that is passed on to PRAS. PRAS is then executed to estimate the total normalized expected unserved energy (NEUE)—where the normalization divides EUE by total contiguous U.S. load—and to

[50] https://www.nrel.gov/analysis/pras.html

identify the days of highest system stress (highest EUE). If a specified NEUE target is met, ReEDS proceeds to the next solve period (e.g., 2040). If the target is not met, ReEDS re-solves for the same solve period but with additional stress periods considered and the iterative process repeats. To limit computational runtimes, an iteration limit is also imposed, where ReEDS proceeds to the next solve period despite not meeting NEUE target; however, this seldom occurs in the scenarios.

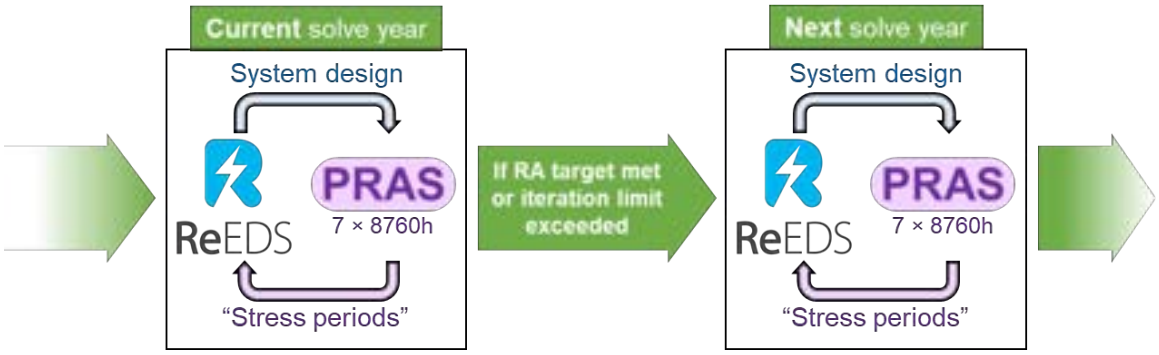



Figure B-1. Integrated capacity expansion and resource adequacy modeling

ReEDS models up to 30 stress periods, which are the periods with highest EUE as estimated by PRAS.[51] During the stress periods, ReEDS models dispatch in largely the same manner as the "representative periods." Important differences are that demand during these periods is elevated by the planning reserve margin (12%–18%), which is based on reference reserve margins from the 2021 NERC Long-Term Reliability Assessment (NERC 2021). Differences between this approach and a traditional planning reserve margin approach—including how it better addresses systems with higher VRE and transmission exchanges—are discussed by Mai et al. (forthcoming).

## B.3 Planning Threshold

There are many metrics used to quantify resource adequacy (RA), with associated target reliability levels used in system planning. Most power systems in the United States quantify RA using LOLE, with a target of LOLE ≤1 day in 10 years (NERC 2023a). LOLE does not capture the severity of loss of load events; a power system that experiences a 1-day interconnection-wide blackout every 10 years and a power system that curtails 1 GW of industrial load on 1 day in 10 years would both satisfy the 1-in-10 LOLE target (Stenclik et al. 2021; Stephen et al. 2022). The EUE, measured in MWh, and load-normalized EUE (NEUE), measured as a percent or parts per million (ppm), metrics are volumetric rather than event-based, so the 1-blackout-in-10-years system would have much higher EUE and NEUE (and thus lower reliability) than the 1-industrial-load-shed-event-in-10-years system. Though NEUE-based system planning based has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In this study, the NEUE metric is used with a conservatively set threshold of 10 ppm. For context, if load were equally distributed across a year, 10 ppm would be equivalent to 5 minutes of complete

[51] The model is seeded with the highest demand period as a stress period to start.

load shedding (blackout) per year, 9% load shedding spread over a one-hour period, or 0.4% load shedding spread over a 24-hour day.

## B.4 Caveats

The integrated ReEDS-PRAS formulation used here attempts to incorporate many of the practices recommended for evaluating systems with significant deployment of renewable energy, storage, and transmission (Stenclik 2023). However, as with any modeling analysis, there are limitations—and this section describes important caveats.

- **Reliability target.** The NEUE reliability metric is used in the scenario modeling for the reasons described previously, but this metric is not yet commonly adopted in practice. Another reliability metric could result in different outcomes. Moreover, because there are trade-offs between cost and reliability, different portfolio outcomes could result if the NEUE threshold assumption of 10 ppm were changed. The 10-ppm threshold is an upper bound in the model implementation; thus, the level of reliability can vary between 0 and 10 ppm across scenarios. Regional NEUE thresholds would also yield outcomes different from the national threshold used here.
- **Weather years.** Most scenarios consider 7 years of historical (2007–2013) weather in the PRAS modeling. Additional weather years would enable a more robust assessment of RA. Future weather conditions could also change and affect demand profiles and the contributions from weather-dependent resources.[52] The Climate Change sensitivity provides one sample of impacts from future weather (see Appendix A).
- **Outages.** PRAS simulates thermal generator and storage outages, but in the modeling these outage rates do not vary with time or weather conditions. In reality, thermal outages are correlated with extreme temperatures (S. Murphy, Sowell, and Apt 2019). PRAS also does not represent transmission outages, which could be a higher source of system risk in the scenarios with significantly expanded transmission.
- **Demand response.** The versions of ReEDS and PRAS used for this study do not include demand response. Demand response is used in some systems to provide RA capacity—e.g., 1.9 GW in CAISO in 2022, roughly 3%–4% of total RA capacity (CAISO 2023b). All unserved energy is included in the NEUE values discussed here, but in practice some of this unserved energy would be served by appropriately compensated demand response and would not be considered to contribute to “dropped load” events. If demand response for RA were included in the simulations, the resulting NEUE would be reduced.

[52] The impact of future electrification on demand profiles are reflected in the scenarios, but demand from the use of these new electrified end uses is based on historical weather in most scenarios.

# Appendix C. Technology Cost Assumptions

The Regional Energy Deployment System (ReEDS) models a large suite of technologies, including electricity generation technologies, energy storage technologies, $CO_2$ capture and storage, and hydrogen-producing technologies.

## C.1 Supply-Side Technologies

Table C-1 lists the electricity generation and storage technologies available in ReEDS and outlines which technologies are deployable under default assumptions in this study and which are included and excluded in various sensitivity cases.

Table C-1. Technologies Modeled in ReEDS

| Technology | Expansion Allowed in Core Scenario | Included Sensitivity Cases | Excluded Sensitivity Cases |
|---|---|---|---|
| 4-Hr Battery[a] | Yes | | |
| 8-Hr Battery[a] | Yes | | |
| Bioenergy with CCS (BECCS) | Yes | | |
| Biopower | Yes | | |
| Concentrating Solar Power (CSP) | Yes | | |
| Geothermal[b] | Yes | | |
| Hydropower[b] | Yes | | |
| Natural Gas Combined Cycle (NG-CC) | Yes | | |
| Natural Gas Combustion Turbine (NG-CT) | Yes | | |
| Land-Based Wind[b] | Yes | | |
| Offshore Wind[b] | Yes | | |
| Pumped Hydropower[b] | Yes | | |
| Utility-Scale Solar PV[b] | Yes | | |
| Coal + Carbon Capture and Storage (Coal-CCS)[d] | Yes | | No CCS; No $H_2$ or CCS |
| Hydrogen Combustion Turbine ($H_2$-CT)[d] | Yes | | No $H_2$; No $H_2$ or CCS; No $H_2$ or new nuclear |

| Technology | Expansion Allowed in Core Scenario | Included Sensitivity Cases | Excluded Sensitivity Cases |
|---|---|---|---|
| **Technology** | **Expansion Allowed in Core Scenario** | **Included Sensitivity Cases** | **Excluded Sensitivity Cases** |
| Natural Gas Combined Cycle with CCS (NG-CC-CCS)[d] | Yes | | No CCS; No $H_2$ or CCS |
| Nuclear | Yes | | No $H_2$ or new nuclear |
| Nuclear Small Modular Reactor (SMR) | No | +Nuclear SMR + DAC | |
| Coal[c] | No, existing capacity only | | |
| Landfill Gas[c] | No, existing capacity only | | |
| Oil-Gas-Steam[c] | No, existing capacity only | | |
| Distributed PV[e] | Expansion is exogenously specified | | |

*[a] ReEDS can model 2-, 4-, 6-, 8-, and 10-hour batteries, but only the 4-hour and 8-hour battery durations are modeled in this study to reduce computation time while allowing for both shorter-duration and longer-duration storage options.*

*[b] Plants of these types are modeled with a supply curve because these technologies have site-specific characteristics and multiple technology configurations. For land-based wind, offshore wind, and utility-scale solar PV, these supply curves and generation profiles are from the reV model.*

*[c] Existing plants of these types are included, but expanded capacity is not allowed in this analysis.*

*[d] Plants of these types can be greenfield builds or retrofits. More detail on retrofits can be found in Appendix C.2.*

*[e] Distributed PV deployment is exogenously specified based on simulations from NREL's Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016). The same distributed PV projection featuring 130 GW of distributed PV capacity by 2035 is used for all scenarios and based on the Standard Scenarios 2023 Mid-case (Gagnon et al. 2024). Distributed PV cannot be curtailed in ReEDS.*

Most scenarios use technology cost and performance assumptions from the 2023 ATB Moderate case. Capital, fixed operation and maintenance, and variable operation and maintenance cost data for the core scenarios are shown in Table C-2, Table C-3, and Table C-4, respectively. Costs for hydropower and geothermal options vary significantly by technology type and location and are therefore not shown in the tables. These costs are based on DOE's Hydropower Vision Report (DOE 2016) and the 2023 ATB (National Renewable Energy Laboratory 2023) for the two technologies, respectively. Other technology assumptions (e.g., heat rate, capacity factor improvements), as well as more conservative or advanced cost assumptions used in the cost sensitivity cases, can be found in the ATB.

Table C-2. Overnight Capital Costs ($/kW) in the Core Scenarios

| Technology | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|
| 4-Hr Battery | 1,551 | 1,300 | 1,199 | 1,099 | 999 | 899 |
| 8-Hr Battery | 2,790 | 2,282 | 2,093 | 1904 | 1,715 | 1,528 |
| BECCS[a] | 7,373 | 7,259 | 7,155 | 7,051 | 6,947 | 6,843 |
| Coal-CCS | 4,943 | 4,641 | 4,339 | 4,102 | 3,866 | 3,629 |
| CSP[b] | 4,529 | 3,658 | 3,528 | 3,397 | 3,266 | 3,136 |
| NG-CC | 1,174 | 1,122 | 1,070 | 1026 | 982 | 938 |
| NG-CC-CCS | 2,424 | 2,179 | 1934 | 1,823 | 1,713 | 1,602 |
| NG-CT | 1,057 | 1,014 | 971 | 928 | 885 | 843 |
| $H_2$-CT[c] | 1,088 | 1,044 | 1,000 | 956 | 912 | 868 |
| Land-Based Wind | 1,194 | 1,083 | 1,029 | 976 | 923 | 869 |
| Nuclear | 6,925 | 6,603 | 6,384 | 6,159 | 5,947 | 5,696 |
| Nuclear SMR | 7,563 | 7,213 | 6,974 | 6,729 | 6,500 | 6,227 |
| Offshore Wind, Fixed-Bottom[d] | 2,228 | 2048 | 1937 | 1,856 | 1,793 | 1,740 |
| Offshore Wind, Floating Platform[d] | 3,329 | 3,071 | 2,912 | 2,796 | 2,705 | 2,630 |
| Utility-Scale Solar PV | 1,300 | 1,082 | 864 | 795 | 727 | 659 |

*[a] Costs shown assume a 90% emissions capture rate. BECCS cost and performance values are from Young (2020).*

*[b] Costs shown for CSP assume 8 hours of thermal energy storage (TES). ReEDS models four classes of CSP technologies, including various durations of TES.*

*[c] Hydrogen combustion turbine capital costs are not included in the ATB. Assumed costs for new $H_2$-CTs are 3% greater than for new NG-CTs (Denholm et al. 2022).*

*[d] Offshore wind costs shown for fixed-bottom technologies are for Wind Resource Class 3, and those shown for floating platform technologies are for Wind Resource Class 10. There are seven classes for each offshore wind technology in the ATB, and each class has different capital costs. See the 2023 ATB for more details (National Renewable Energy Laboratory 2023).*

Table C-3. Fixed Operation and Maintenance Costs in $/(kW-year) in the Core Scenarios

| Technology | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|
| 4-Hr Battery | 38.8 | 32.5 | 30.0 | 27.5 | 25.0 | 22.5 |
| 8-Hr Battery | 69.8 | 57.1 | 52.3 | 47.6 | 42.9 | 38.2 |
| BECCS | 217 | 217 | 217 | 217 | 217 | 217 |
| Coal-CCS | 129 | 122 | 115 | 110 | 104 | 98.7 |
| CSP | 47.1 | 39.7 | 39.7 | 39.7 | 39.7 | 39.7 |
| NG-CC | 32.6 | 31.0 | 29.3 | 28.2 | 27.1 | 26.0 |
| NG-CC-CCS | 64.9 | 58.3 | 51.7 | 49.0 | 46.3 | 43.6 |
| NG-CT | 25.5 | 24.7 | 24.1 | 23.3 | 22.6 | 21.9 |
| $H_2$-CT | 23.7 | 23.7 | 23.7 | 23.7 | 23.7 | 23.7 |
| Land-Based Wind | 28.8 | 27.0 | 26.1 | 25.2 | 24.2 | 23.3 |
| Nuclear | 164 | 164 | 164 | 164 | 164 | 164 |
| Nuclear SMR | 128 | 128 | 128 | 128 | 128 | 128 |
| Offshore Wind, Fixed-Bottom | 107 | 97.6 | 91.3 | 86.5 | 82.7 | 79.5 |
| Offshore Wind, Floating Platform | 80.3 | 73.8 | 69.4 | 66.1 | 63.4 | 61.2 |
| Utility-Scale Solar PV | 22.1 | 19.4 | 16.8 | 16.0 | 15.3 | 14.6 |

Table C-4. Variable Operations and Maintenance Costs in $/MWh in the Core Scenarios

| Technology | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|
| 4-Hr Battery | 0 | 0 | 0 | 0 | 0 | 0 |
| 8-Hr Battery | 0 | 0 | 0 | 0 | 0 | 0 |
| BECCS | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 |
| Coal-CCS | 15.4 | 14.7 | 14.0 | 13.7 | 13.5 | 13.2 |
| CSP | 2.6 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| NG-CC | 2.1 | 2.0 | 1.9 | 1.9 | 1.8 | 1.7 |
| NG-CC-CCS | 4.8 | 4.4 | 4.0 | 3.9 | 3.7 | 3.6 |
| NG-CT | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| $H_2$-CT | 5.6 | 5.6 | 5.6 | 5.6 | 5.6 | 5.6 |
| Land-Based Wind | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| Nuclear SMR | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| Offshore Wind, Fixed-Bottom | 0 | 0 | 0 | 0 | 0 | 0 |
| Offshore Wind, Floating Platform | 0 | 0 | 0 | 0 | 0 | 0 |
| Utility-Scale Solar PV | 0 | 0 | 0 | 0 | 0 | 0 |

## C.2 Retrofits With CCS

Existing fossil-fuel-fired capacity is allowed to retrofit with carbon capture and storage. Retrofits are allowed starting in 2030. Capital costs for retrofits and capacity derates are based on data from EIA NEMS assumptions (EIA 2023b) as described in Table C-5.

Table C-5. Retrofit Assumptions for Technologies in ReEDS

| Original Technology | Retrofit Technology | Capital Costs | Capacity Derate |
|---|---|---|---|
| Coal | Coal-CCS | Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $3,100/kW in 2023 and decrease to $1,600/kW by 2050 (National Renewable Energy Laboratory 2023). | Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 29% derate after retrofitting. |
| NG-CC | NG-CC-CCS | Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $1,690/kW in 2023 and decrease to $1,010/kW by 2050 (National Renewable Energy Laboratory 2023). | Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 14% capacity derate after retrofitting. |

## C.3 Negative Emissions Technologies

ReEDS models two negative emissions technologies: bioenergy with CCS (BECCS) and direct air capture (DAC). BECCS is enabled by default in these scenarios and allowed to expand. The cost assumptions for BECCS are shown in Appendix C.1 because BECCS is also a supply-side technology. BECCS is assumed to have a 90% capture rare and an emissions rate of -0.060 metric tons $CO_2$ per MMBtu. DAC is turned off by default but enabled in the +Nuclear SMR + DAC scenario. The assumed levelized cost of DAC is between $300 and $400 per metric ton of $CO_2$ captured and sequestered based on Brown et al. (forthcoming).

The national $CO_2$(e) emissions constraint in ReEDS is modeled on a net basis, meaning negative emissions technologies can offset (positive) emissions to reach the desired target level. However, offsets of emissions are allowed only from fossil with CCS. Based on this definition, generation from fossil plants without CCS is not allowed when the requirement is net zero (e.g., after 2035 under the 100% by 2035 scenarios or after 2045 under the 90% by 2035 scenarios).

## C.4 Financing and Retirement Assumptions

The economic lifetime assumptions for various technologies are shown in Table C-6. Most generators are assumed to have a 20-year economic lifetime whereas 15 years is assumed for batteries and electrolyzers and 40 years for transmission.

There are multiple ways plants can retire:

- **Announced retirements.** Plants that have announced their retirement date (EIA 2023b) are retired during that year.
- **Age-based retirements.** Plants must retire on or before their maximum age as shown in Table C-6. Utility-scale solar PV, distributed scale solar PV, land-based wind, and offshore wind can be repowered—with the associated new plant capital cost but without the need for new interconnection costs—once they reach their maximum age.
- **Endogenous retirements.** The model decides to retire capacity to avoid ongoing operation and maintenance and fuel costs if the plant does not receive sufficient value or revenue in the model. This is allowed only for fossil fuel plants.
- **Policy-based retirements.** Certain technologies in ReEDS regions and model years are forced to retire because of policy requirements.

Table C-6. Financing and Maximum Age Assumptions for Technologies in ReEDS

| Technology | Economic Lifetime (years) | Maximum Age (years) |
|---|---|---|
| Hydropower | 20 | * |
| (Non-hydro) Renewable energy (wind, solar PV, geothermal, CSP) | 20 | 30 |
| Coal (with and without CCS) | 20 | 70 |
| NG-CC (with and without CCS) | 20 | 55 |
| NG-CTs and $H_2$-CTs | 20 | 55 |
| Nuclear | 20 | 80 |
| Nuclear SMR | 20 | 80 |
| Storage (pumped hydropower) | 20 | * |
| Storage (batteries) | 15 | 15 |
| Electrolyzer | 15 | * |
| Transmission | 40 | * |

** No maximum age is modeled for these technologies.*

# Appendix D. Additional Results

## D.1 ReEDS Results for 2035

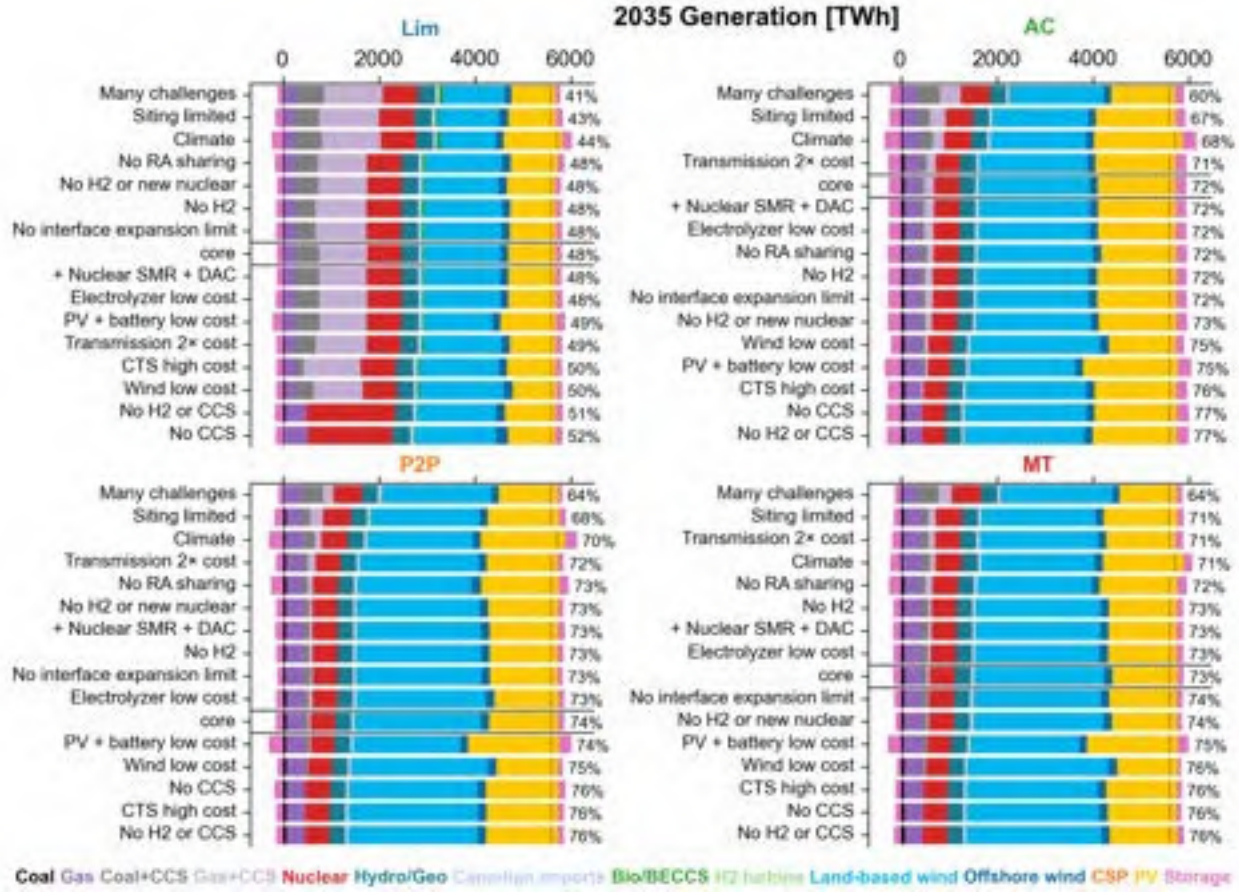



Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

*Within each transmission framework, the sensitivity cases are sorted by 2035 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.*

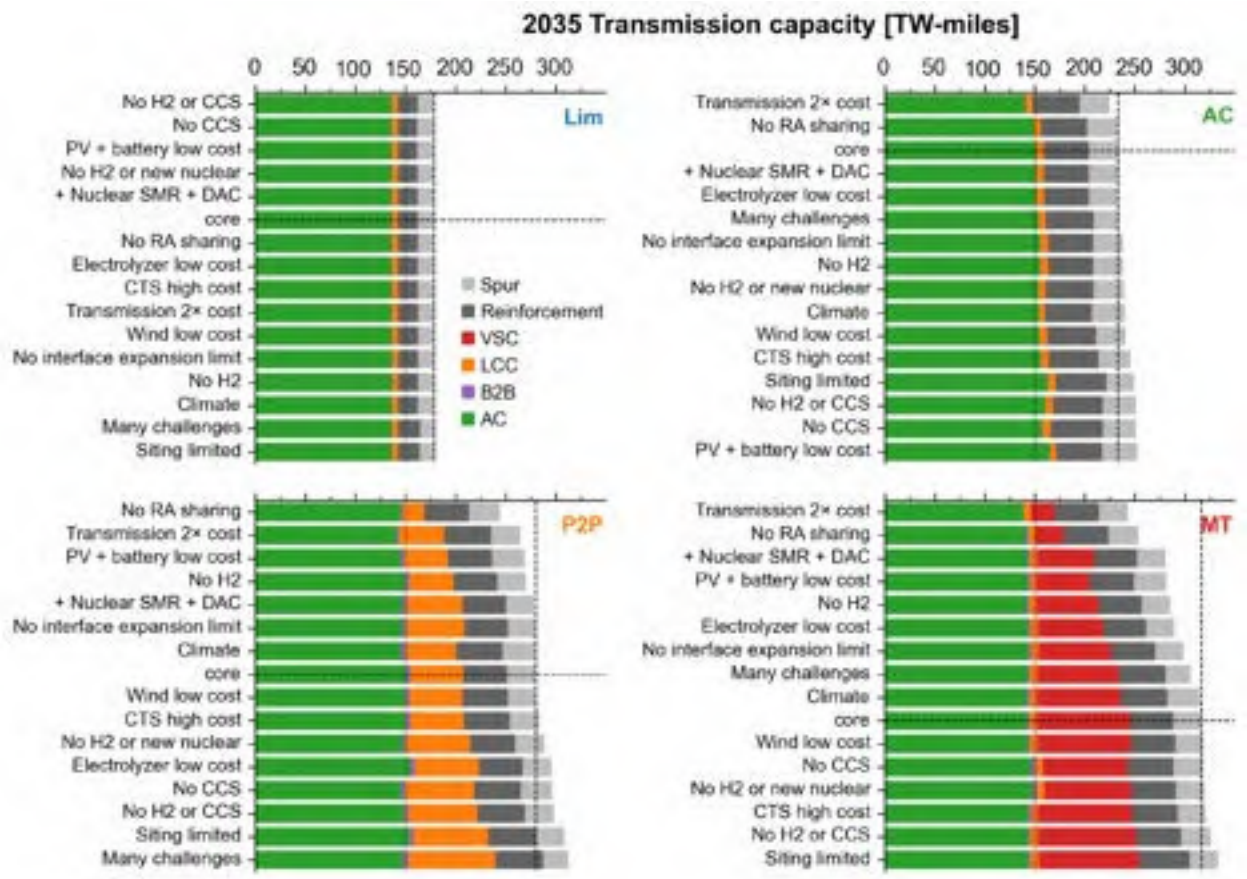



Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

*Values for the core scenario for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2035. The 1.83 TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2035 transmission capacity the same in all sensitivity cases for this framework.*

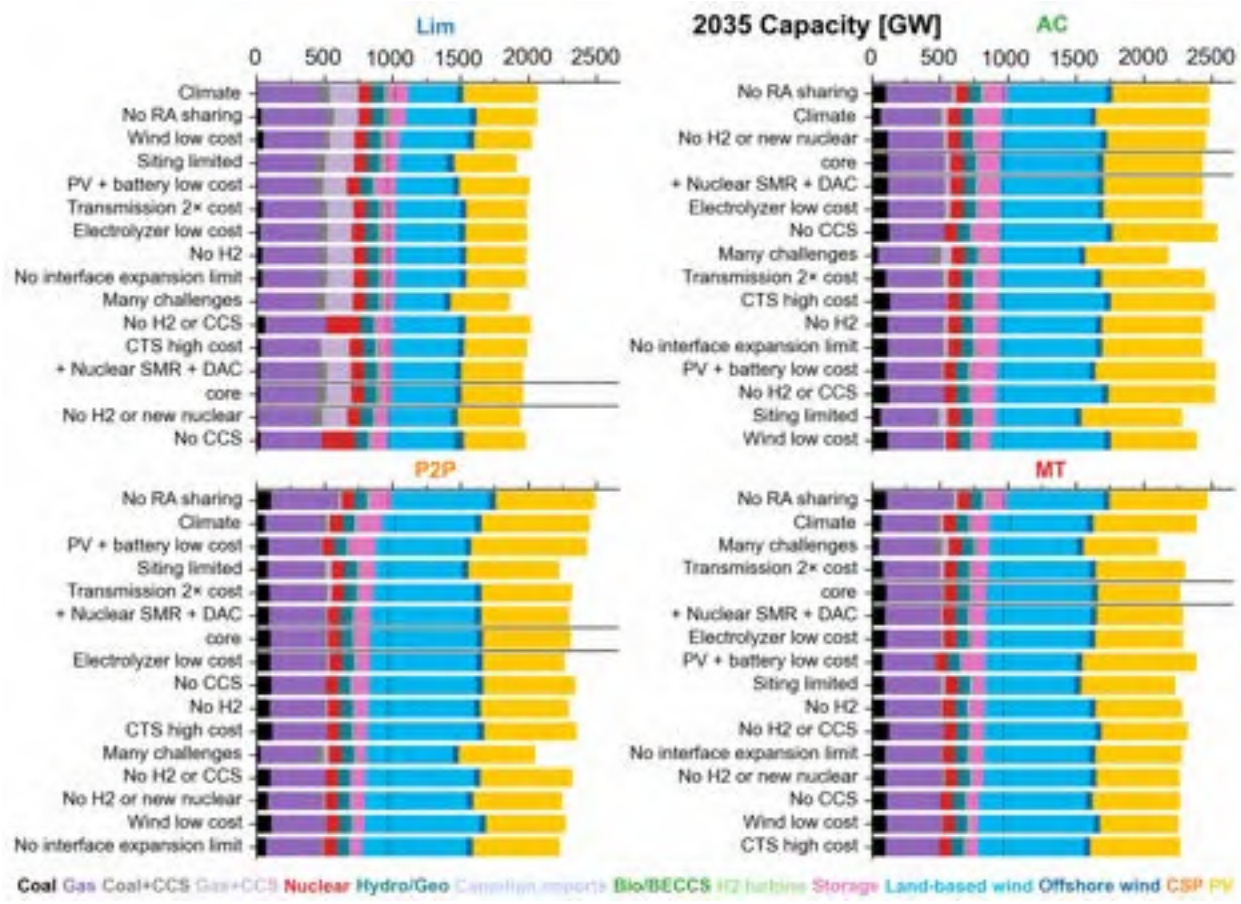



Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

*Within each transmission framework, the sensitivity cases are sorted by 2035 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.*

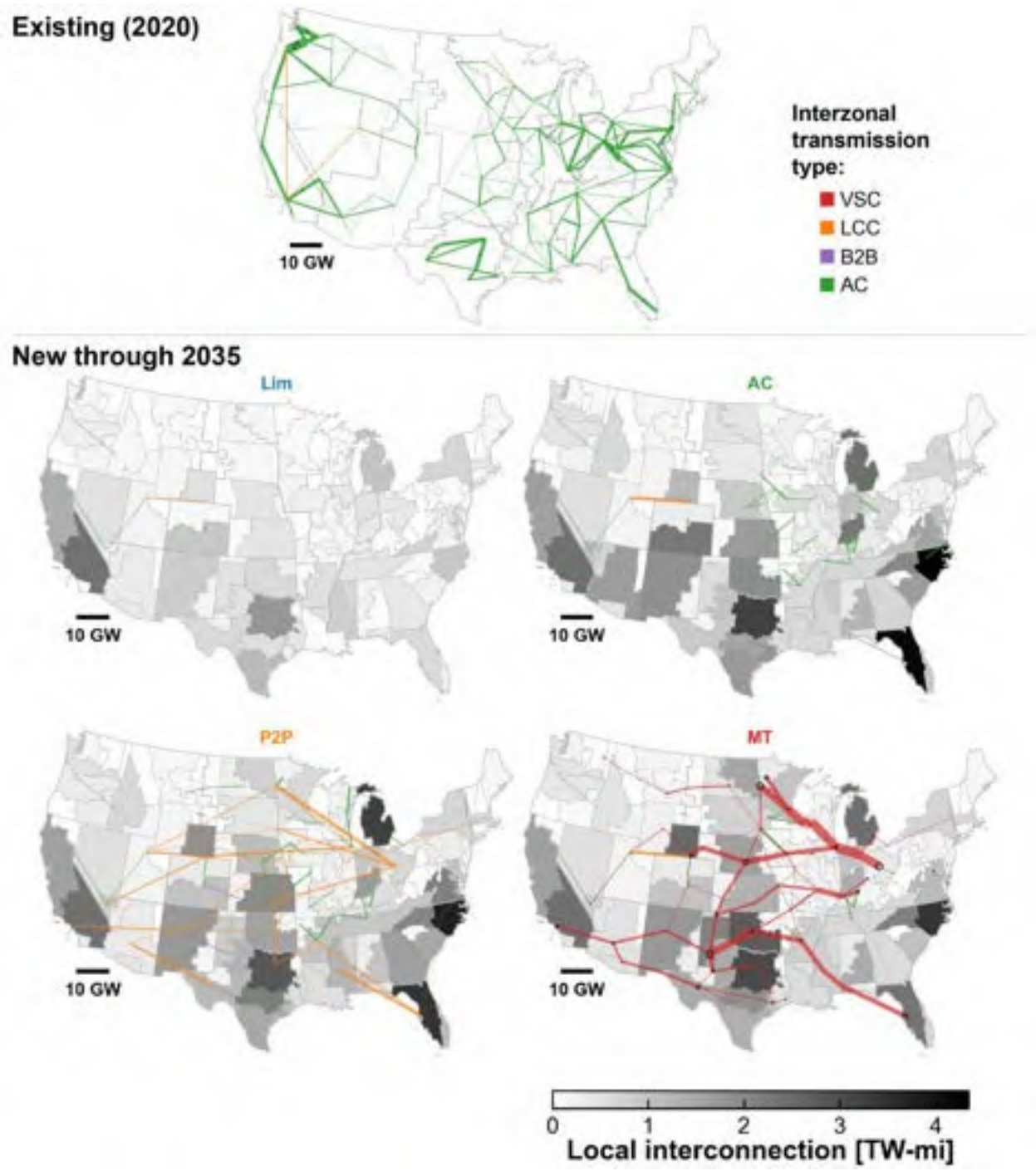



Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

*Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.*

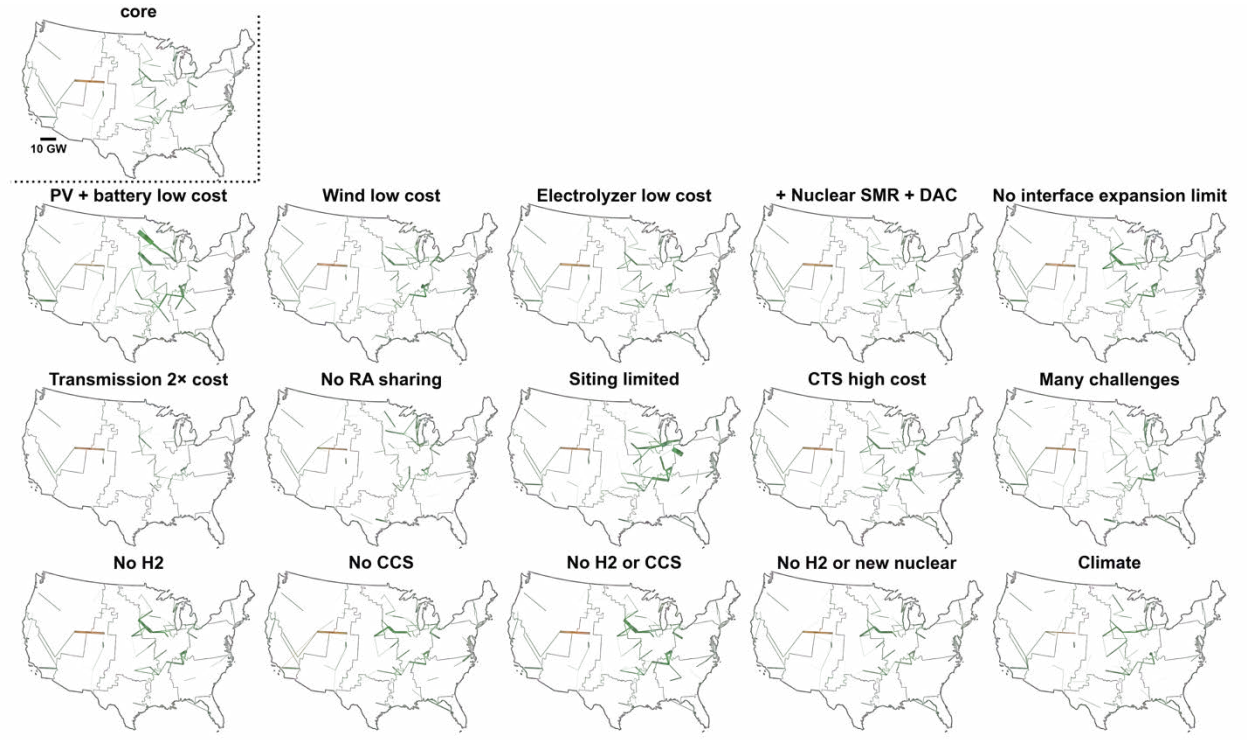



Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

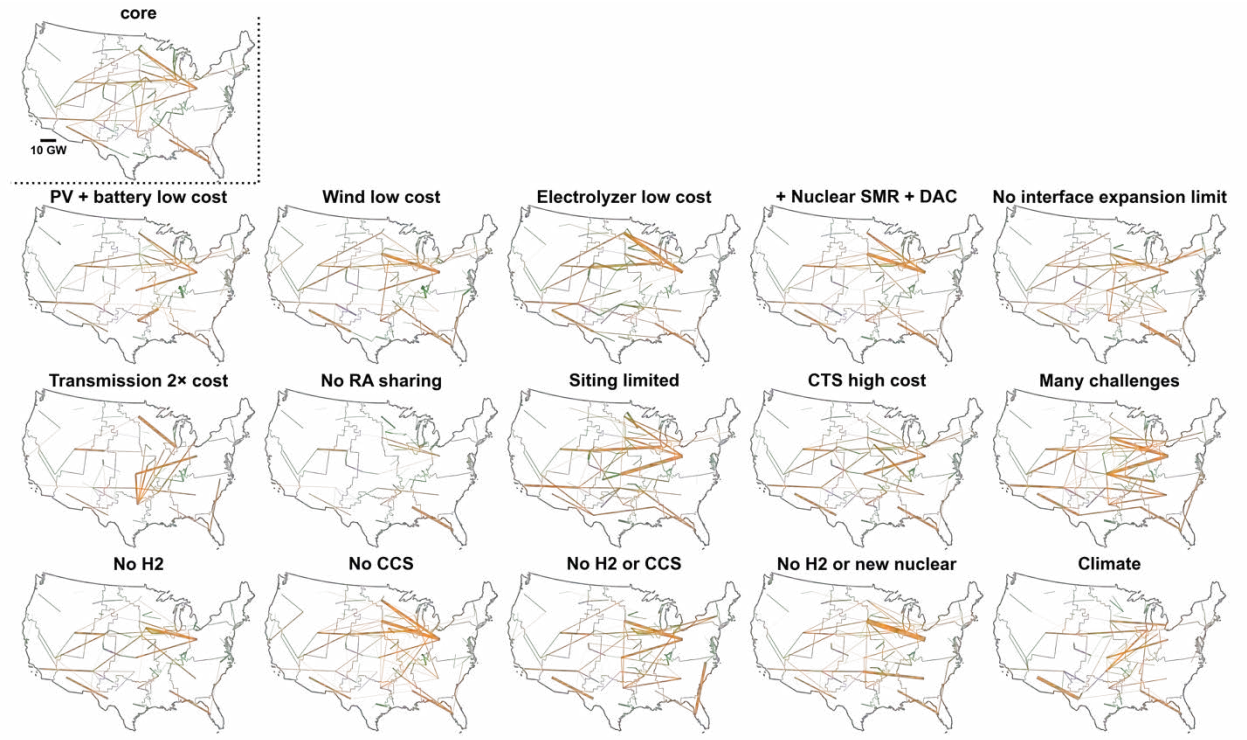



Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

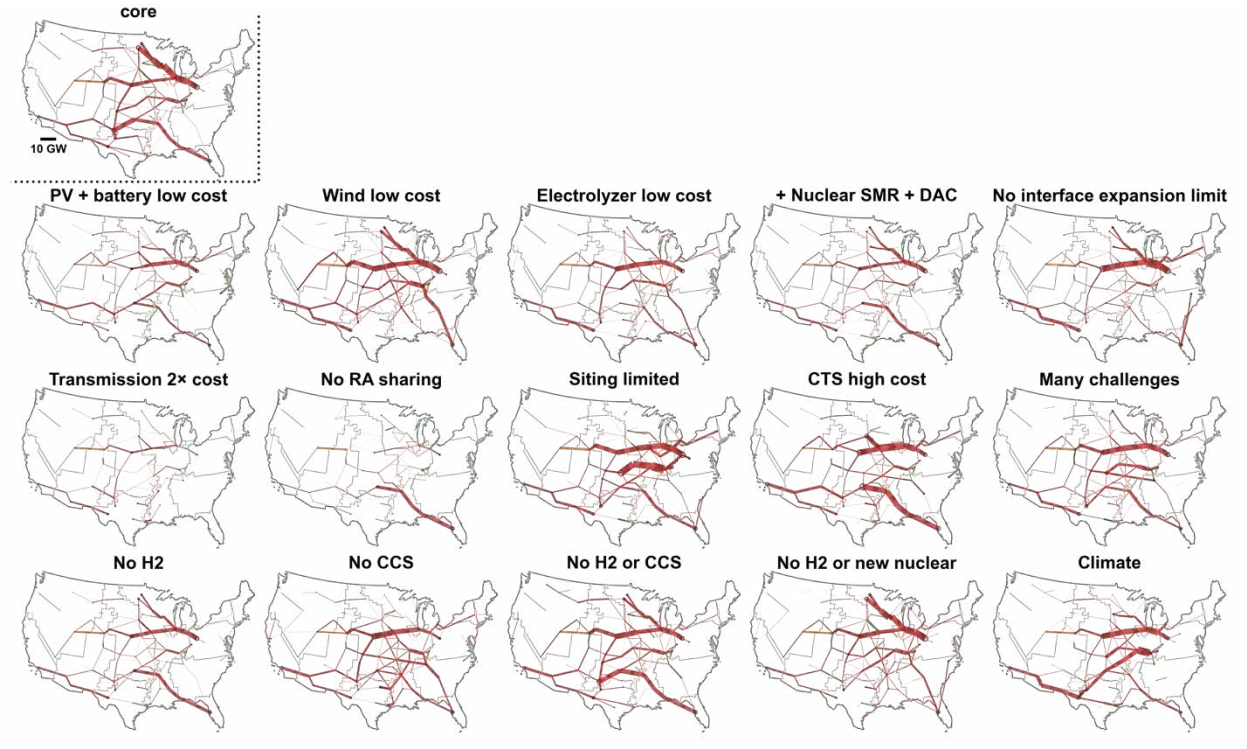



Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

## D.2 Additional Capacity Expansion Modeling Results Through 2050

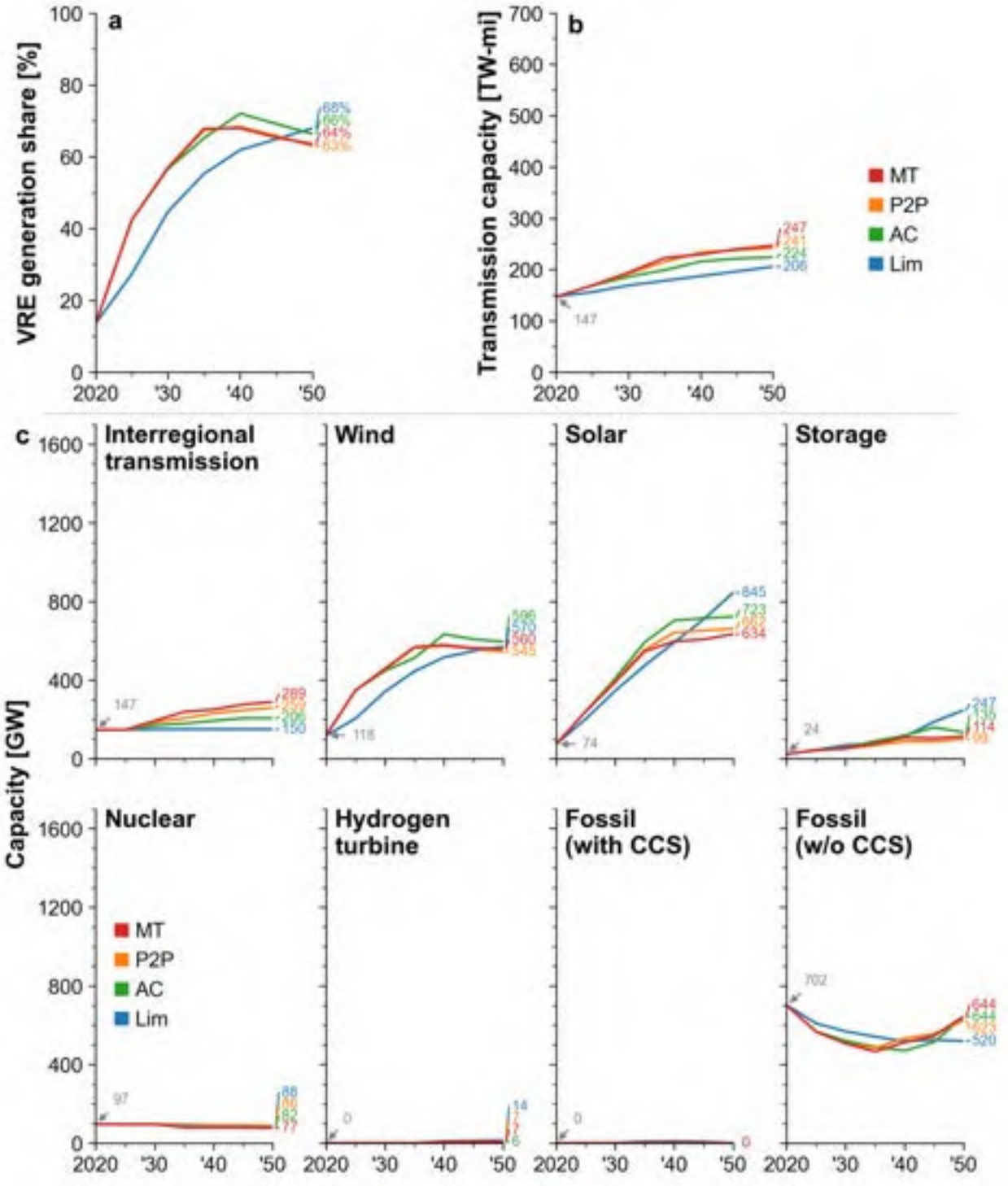



Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

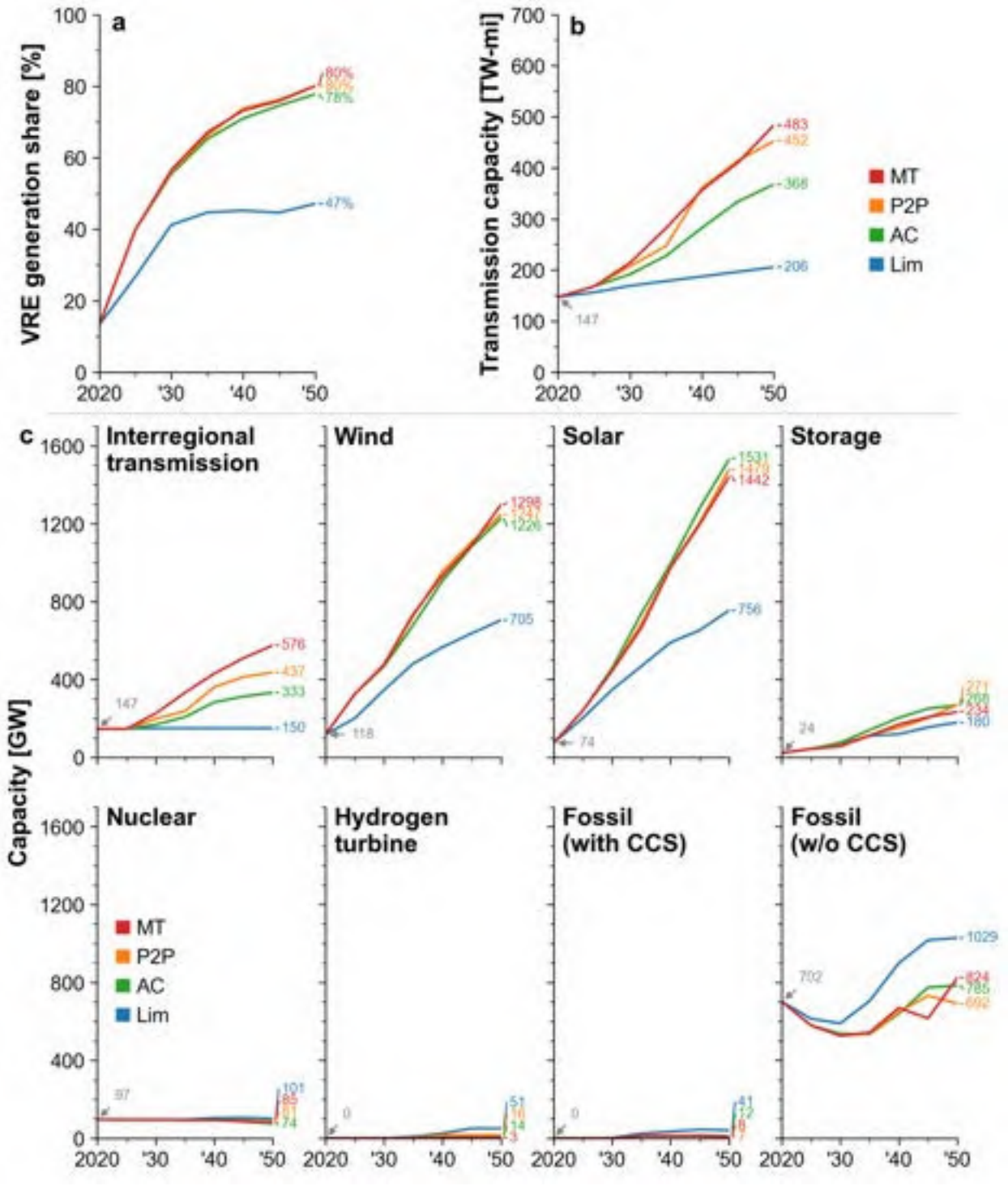



Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

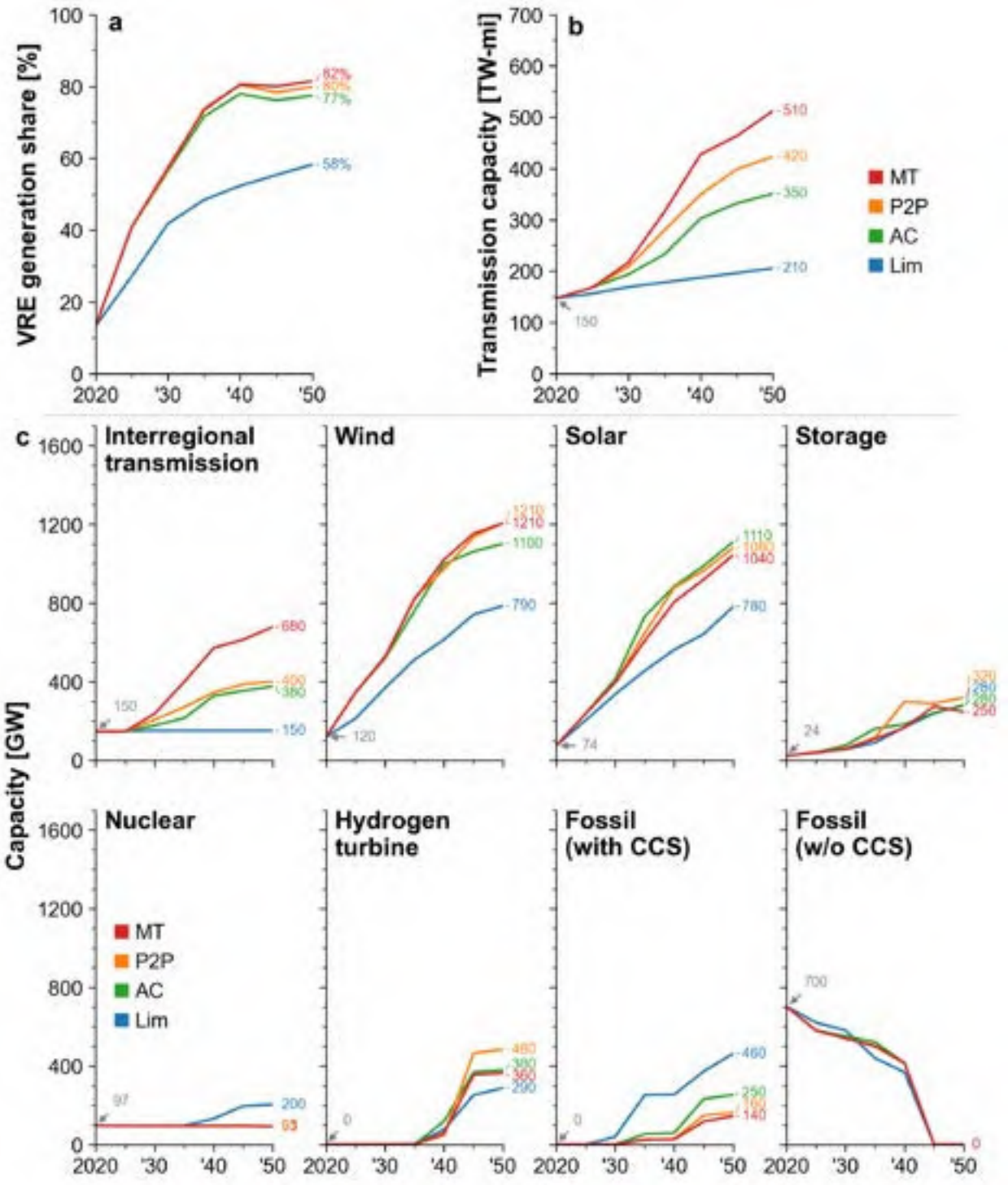



Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

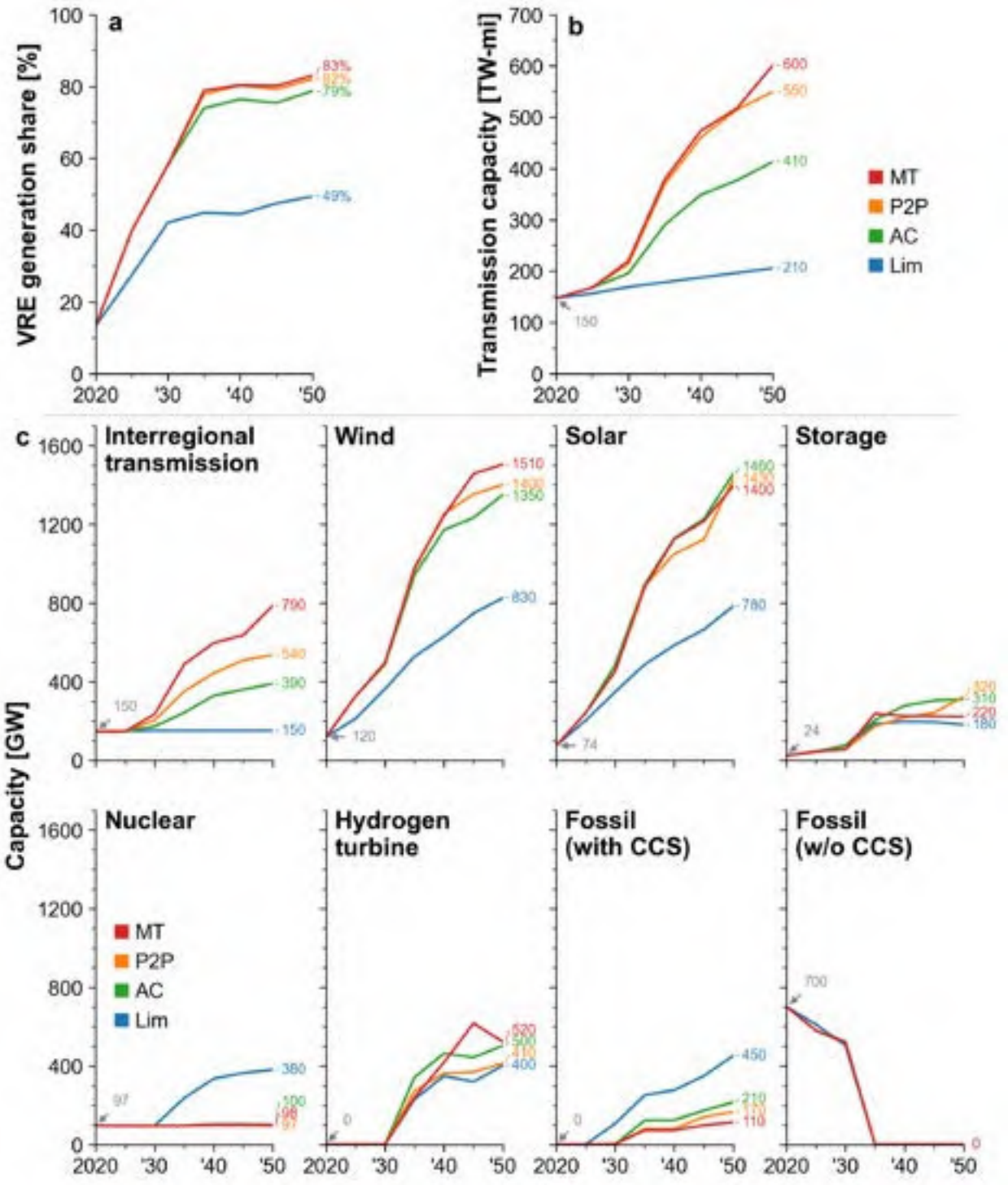



Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

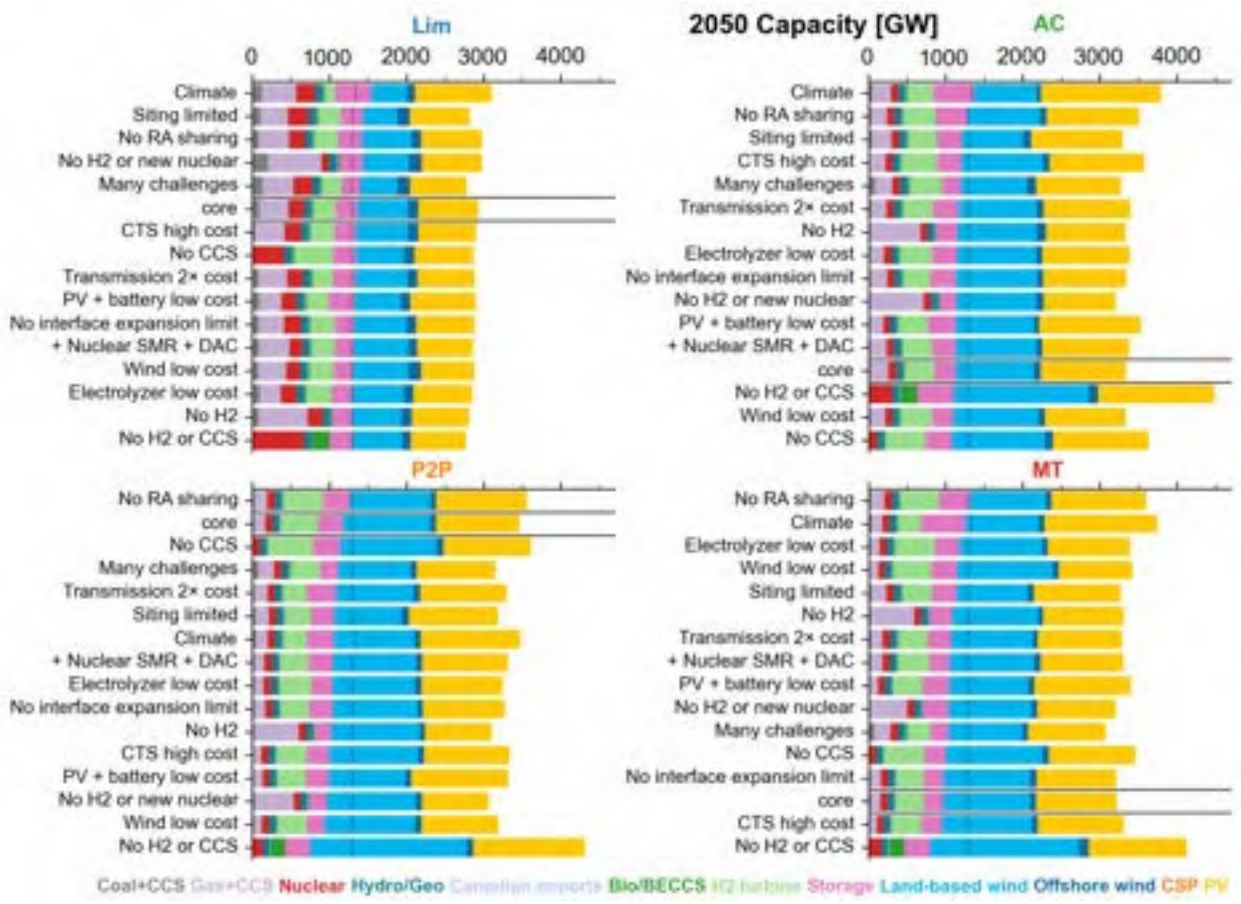



Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

*Within each transmission framework, the sensitivity cases are sorted by 2050 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.*

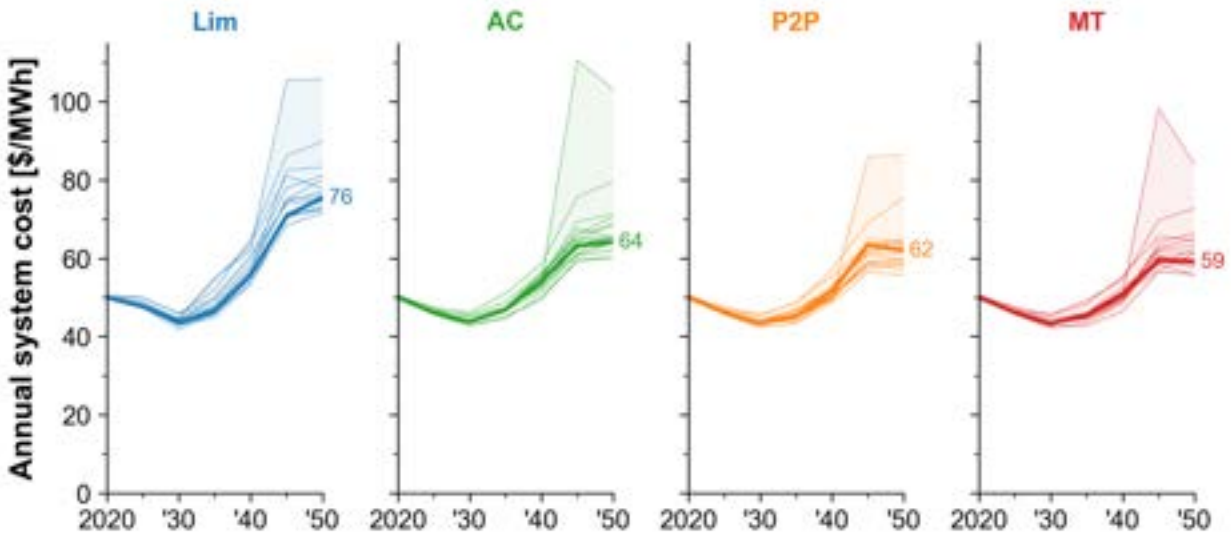



Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

*Annual system cost is given by the sum of undiscounted annualized electricity system expenditures (fixed and operating) and tax credits, divided by annual end-use electricity demand (excluding induced demand from storage charging, $H_2$ production for use in $H_2$-CTs, and transmission losses).*

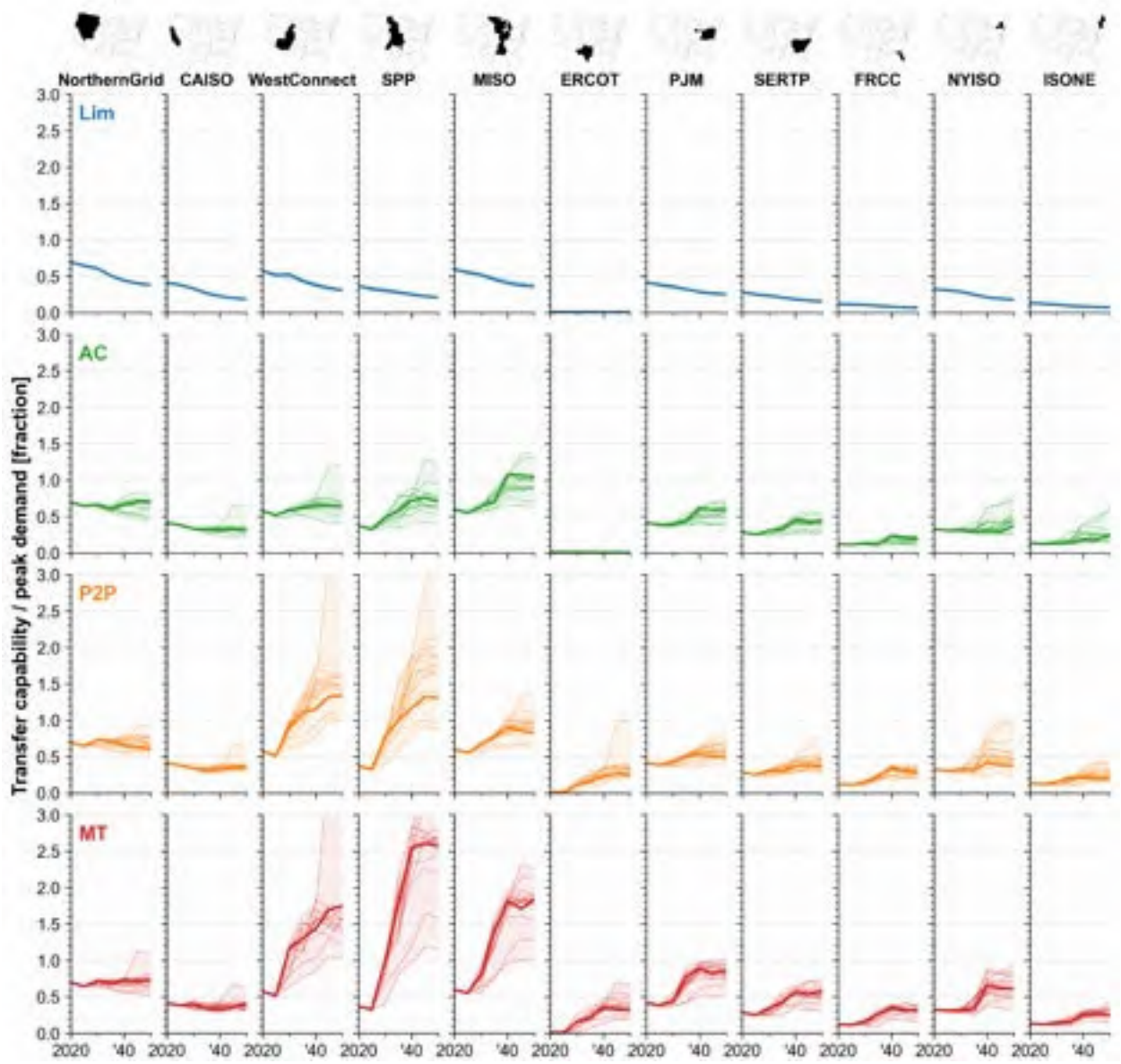



Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

*Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.*

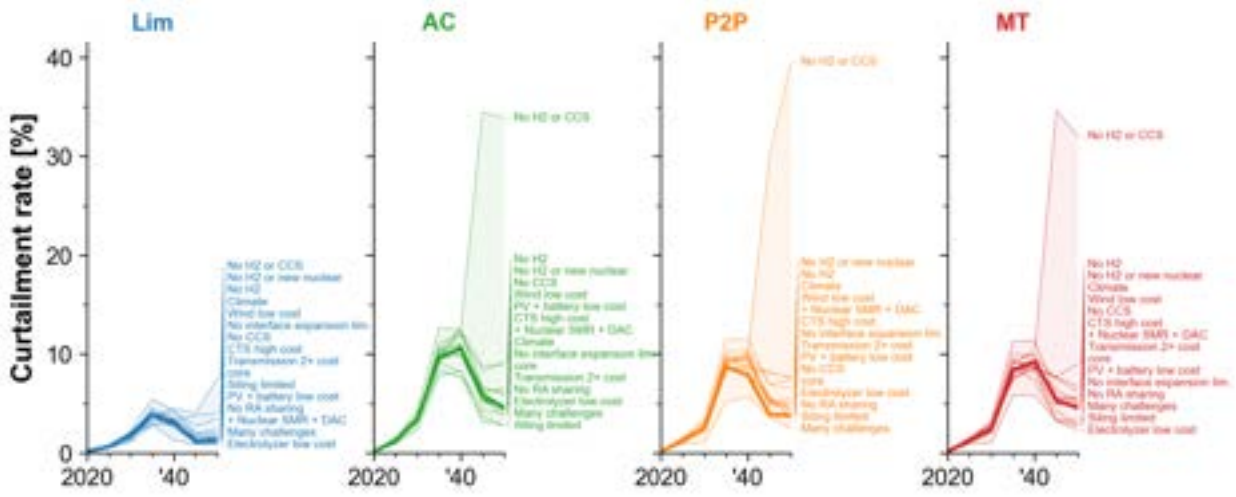



Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

## D.3 Additional Resource Adequacy Results

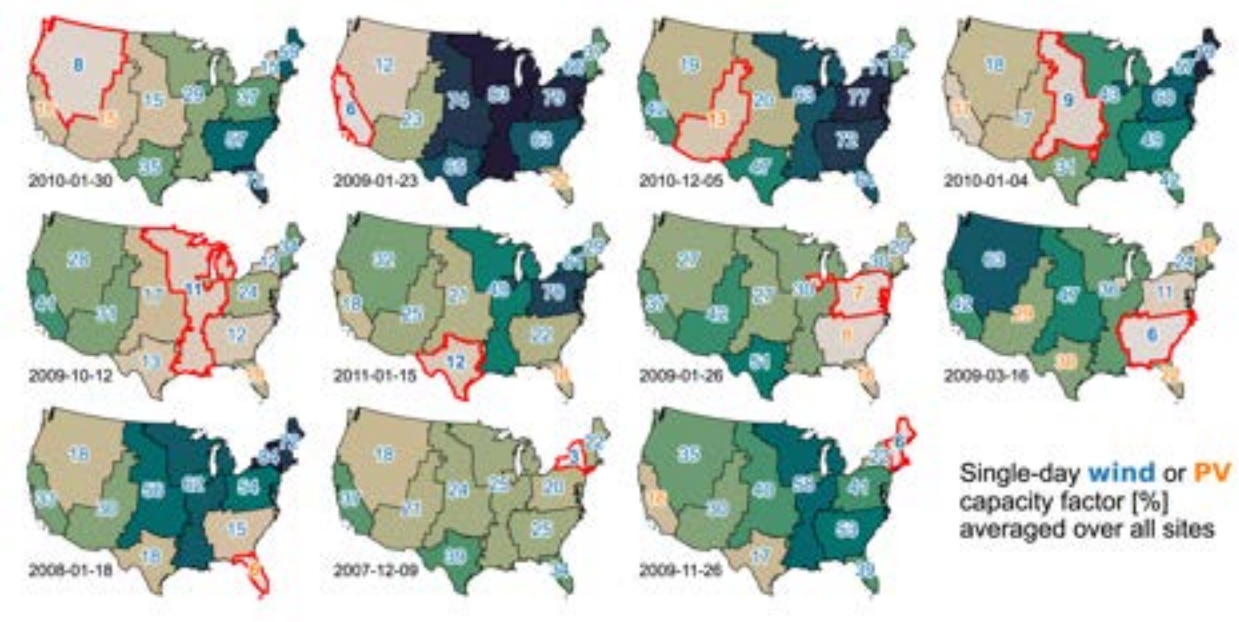



Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

*For each map, the focused planning region is outlined in red, the date of the least-windy/sunny day in that region is given in the lower left, and the values and shading in each region represent the daily wind or PV capacity factor on that date, whichever is larger. (For example, on 2010-01-30, the wind capacity factor in NorthernGrid is 8% and the solar capacity factor is ≤8%; on the same day, the solar capacity factor in CAISO is 16%.) Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.*

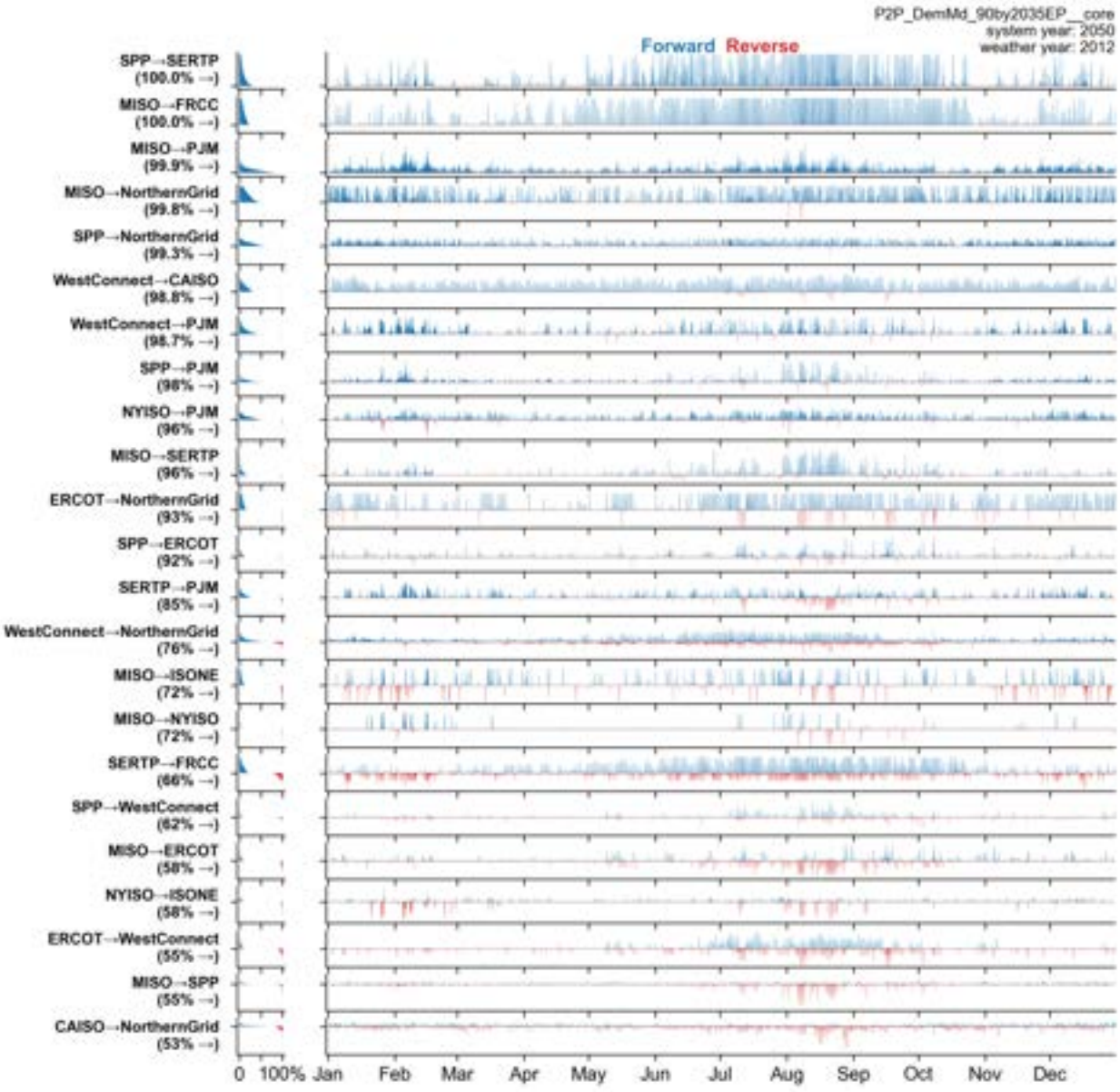



Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

*Interfaces are labeled according to the predominant direction of flow. Flow in the predominant ("forward") direction is shown as positive blue values; flow in the "reverse" direction is shown as negative red values. Interfaces are sorted and labeled by the fraction of total flow in the "forward" direction on a MWh basis over the 7 weather years spanning 2007–2013. Distributions on the left include all weather years; hourly profiles on the right include only 2012 for clarity.*

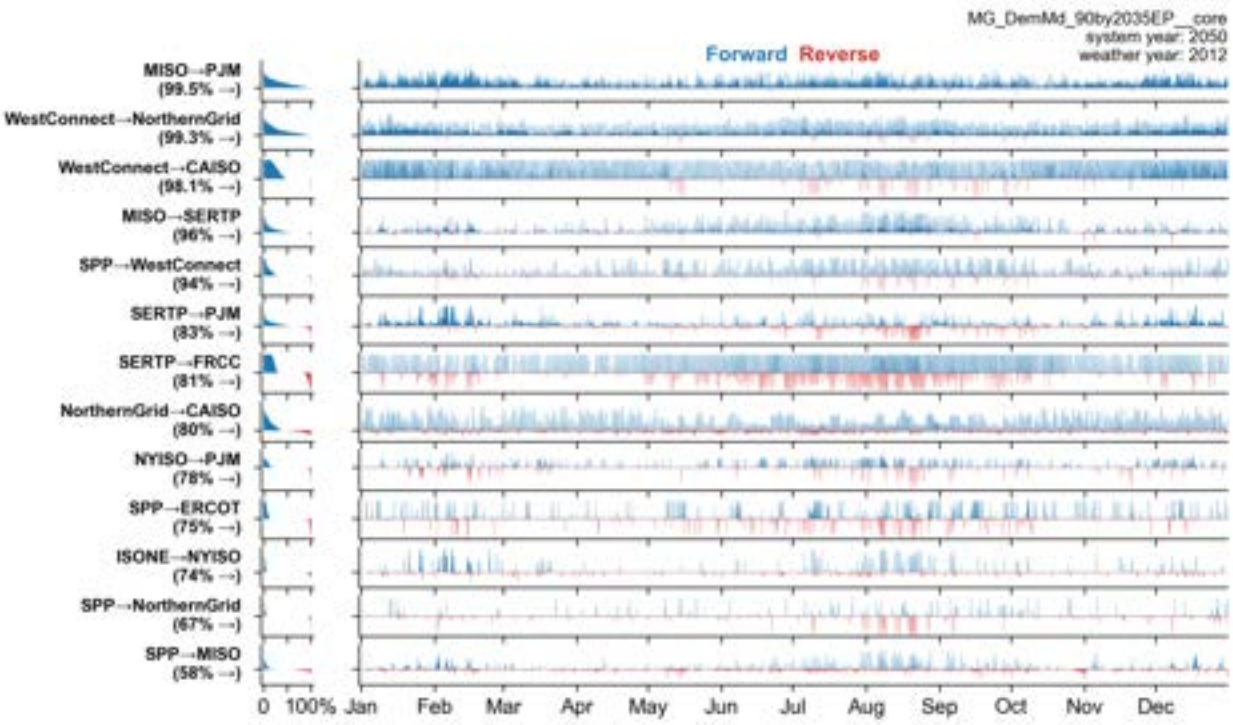



Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

*Data are presented in the same manner as Figure D-9.*

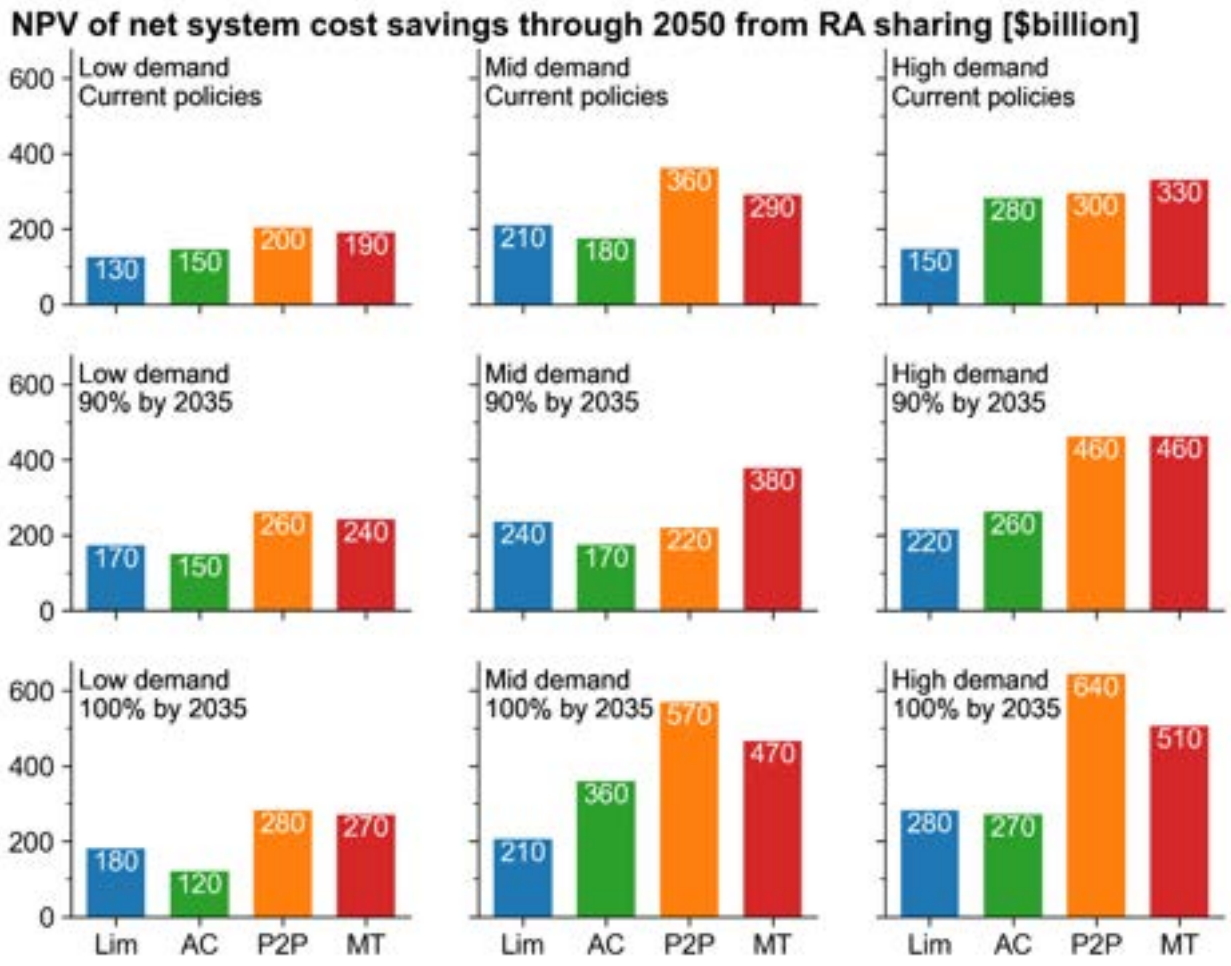



Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

*Data are presented in the same manner as Figure 40a. The "No RA Sharing" sensitivity case was run for each set of demand and emissions assumptions to generate this figure.*

## D.4 Regional Economic Benefits

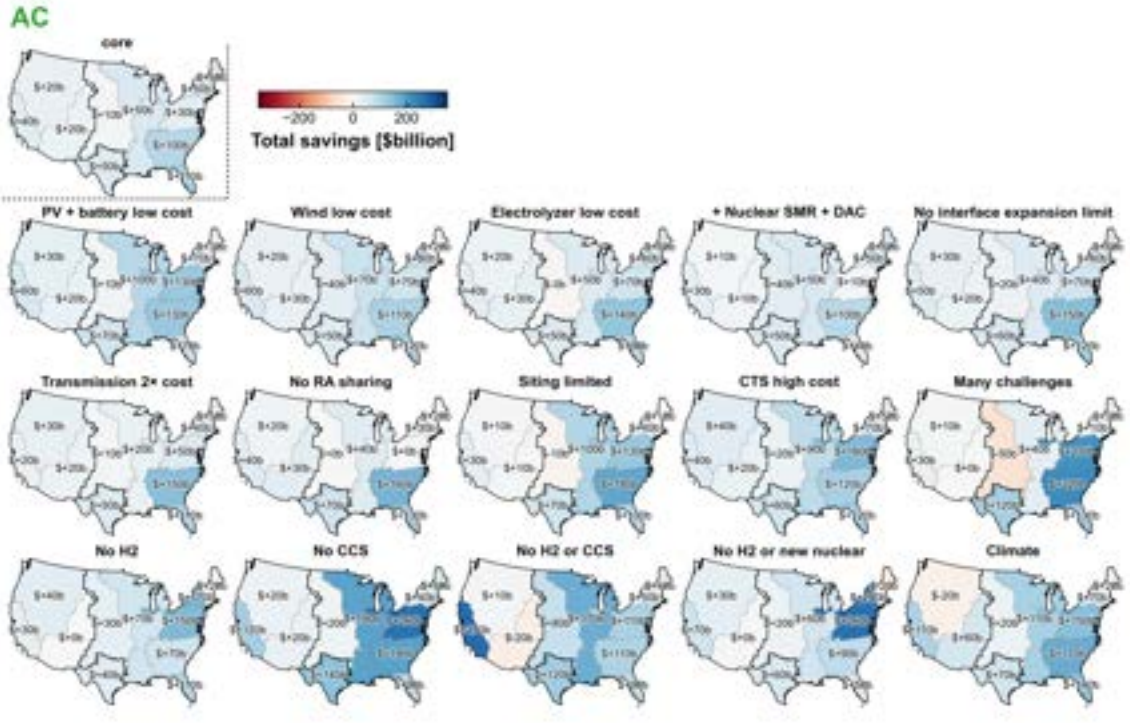



Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

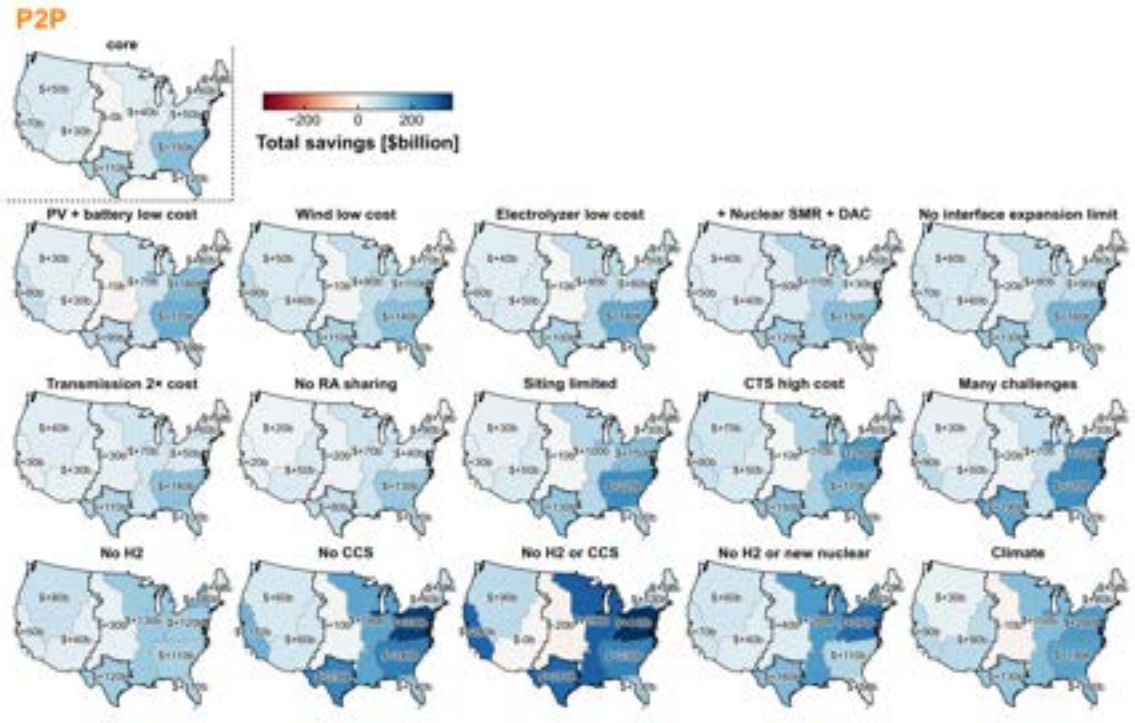



Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

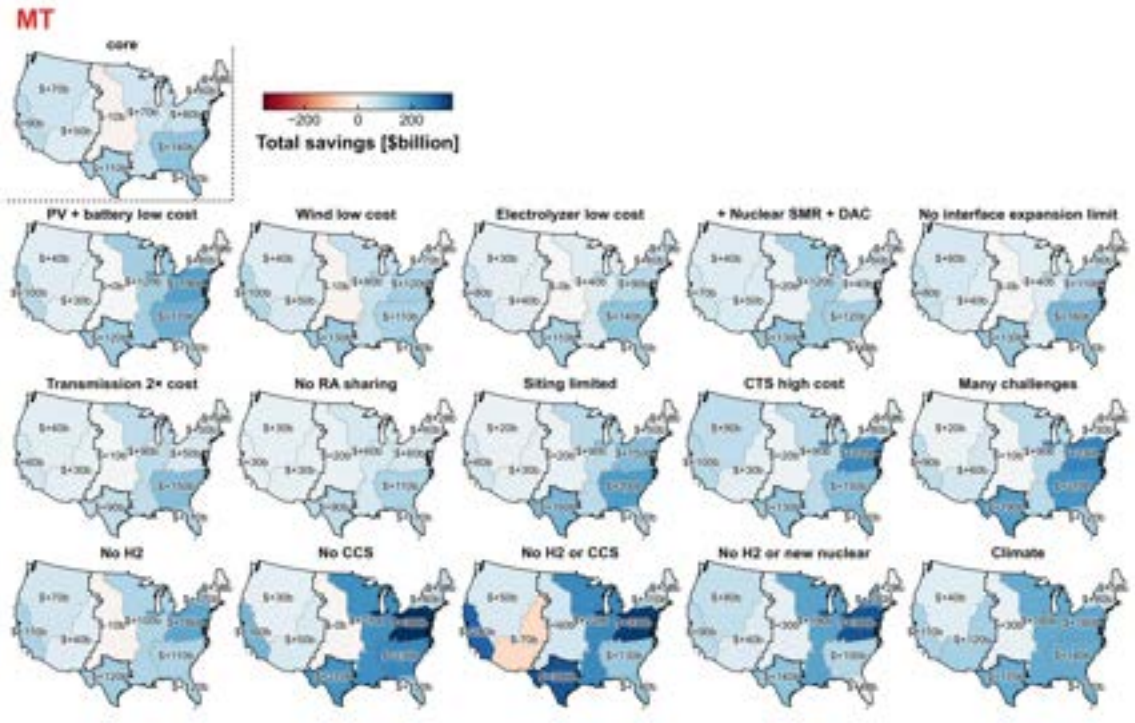



Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

Table D-1. Wind and Solar Capacity (GW) by State in the Core Mid-Demand 90% by 2035 Scenarios

| | Land-based wind | | | | | | | | Utility-scale solar | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2035 | | | | 2050 | | | | 2035 | | | | 2050 | | | |
| | Lim | AC | P2P | MT | Lim | AC | P2P | MT | Lim | AC | P2P | MT | Lim | AC | P2P | MT |
| AL | 3.7 | 8.6 | 7.3 | 12.4 | 8.1 | 12.6 | 24.3 | 16.8 | 3.2 | 23.2 | 17.1 | 16.5 | 18.3 | 50.5 | 31.1 | 43.6 |
| AR | 10.4 | 12.2 | 20.7 | 14.4 | 15.3 | 12.8 | 26.4 | 21.8 | 1.8 | 1.8 | 1.8 | 3.1 | 1.6 | 4.6 | 18 | 4.8 |
| AZ | 3.3 | 6.2 | 2.8 | 4.1 | 3.5 | 10.4 | 20.3 | 3.8 | 19.1 | 42.7 | 19 | 22.4 | 27.8 | 62.5 | 19.2 | 41 |
| CA | 7.5 | 8.1 | 7.8 | 8.9 | 8.9 | 12 | 12.2 | 10.3 | 28 | 32.5 | 33.5 | 33.6 | 25.7 | 40.5 | 46.1 | 47.9 |
| CO | 12.3 | 15.9 | 9.3 | 7.8 | 13.1 | 26.9 | 15 | 13.6 | 3.5 | 7.7 | 8.5 | 9.2 | 12 | 12.5 | 11.1 | 12.4 |
| CT | 0.6 | 0.7 | 0.7 | 0.7 | 0.6 | 1.3 | 1.1 | 1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.3 | 0.3 | 0.3 | 0.3 |
| DE | 1.3 | 1.9 | 2.7 | 1.9 | 2.1 | 1.9 | 2.7 | 1.9 | 2.2 | 0.3 | 0.3 | 0.3 | 4.3 | 4.3 | 2.7 | 2.2 |
| FL | 3.2 | 17.7 | 12.2 | 6.7 | 3.6 | 27.4 | 15.6 | 17.7 | 18.2 | 56.8 | 54.1 | 44.5 | 35.8 | 103.7 | 82.8 | 74.8 |
| GA | 0 | 4.2 | 13.7 | 3.1 | 2.3 | 4.2 | 14.3 | 16.6 | 4.7 | 4.7 | 4.7 | 4.7 | 2.7 | 13.8 | 2.7 | 2.7 |
| IA | 15.9 | 13.4 | 16.1 | 13.4 | 19.2 | 7.7 | 15.3 | 40.6 | 2.3 | 6.9 | 0.3 | 0.3 | 2.3 | 6.9 | 1.9 | 7.6 |
| ID | 7.2 | 8.2 | 7.7 | 9.8 | 10.7 | 15.4 | 12.5 | 15.4 | 0.4 | 8.6 | 10.2 | 3.8 | 1.1 | 15.9 | 11.4 | 12.5 |
| IL | 18.5 | 22.2 | 17.7 | 16.8 | 24.9 | 19.5 | 31.9 | 39.7 | 9.3 | 11 | 5.8 | 5.3 | 11.9 | 10.9 | 7.8 | 10.2 |
| IN | 17.1 | 34.7 | 24.8 | 24.4 | 27.9 | 33.5 | 36.9 | 33 | 5.5 | 33.2 | 33 | 26.9 | 7.2 | 41.2 | 43.1 | 34.4 |
| KS | 10.6 | 14.9 | 18 | 13.1 | 11.5 | 14.9 | 19.4 | 19.7 | 2.8 | 22.1 | 26.4 | 19.4 | 5.3 | 26.4 | 30.6 | 31 |
| KY | 10.9 | 23.7 | 12.9 | 14.7 | 17.6 | 24.2 | 20.7 | 20.2 | 13.6 | 22.4 | 27 | 25.5 | 44.1 | 44.6 | 58.4 | 52 |
| LA | 9.3 | 17.9 | 18.3 | 17.9 | 14 | 23.9 | 29.1 | 25.6 | 7.5 | 7.7 | 4.9 | 4.4 | 13.1 | 18.1 | 8.4 | 10.2 |
| MA | 0.1 | 0.1 | 0.2 | 0.2 | 1.7 | 1 | 1.5 | 0.6 | 1.4 | 1.4 | 1.4 | 1.4 | 0.7 | 0.7 | 0.7 | 0.7 |
| MD | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 3.9 | 3.1 | 3.1 | 3.1 | 5.8 | 5.4 | 5.5 | 5.4 |
| ME | 2.9 | 3.1 | 3.1 | 3.1 | 2.7 | 4.5 | 4.7 | 5.4 | 0.8 | 0.8 | 0.8 | 0.8 | 0.7 | 1.7 | 0.7 | 0.7 |
| MI | 22.3 | 38.8 | 52.3 | 38.8 | 26.1 | 73.9 | 53 | 46 | 5.6 | 10.2 | 2 | 4.7 | 9.7 | 34.3 | 8.9 | 9.8 |
| MN | 13.9 | 18.1 | 34.1 | 46.1 | 20.9 | 22.7 | 47.1 | 48.2 | 5.1 | 5.2 | 1.2 | 1.2 | 4.9 | 5.7 | 0.2 | 10.4 |
| MO | 15.9 | 19.8 | 23.6 | 16.2 | 29.8 | 30.6 | 27.3 | 61.2 | 15.4 | 10.6 | 6.2 | 8.5 | 21.8 | 11.2 | 17 | 9.7 |
| MS | 19.7 | 22.7 | 30.3 | 22.6 | 23.7 | 33.8 | 38.5 | 41.9 | 23.9 | 20.1 | 23.1 | 14 | 41.9 | 27 | 25.4 | 18.8 |
| MT | 7.9 | 7.2 | 5.5 | 9.4 | 10.2 | 10.9 | 6.4 | 9.5 | 0.9 | 1.2 | 1.9 | 0.8 | 1.3 | 1.2 | 3.3 | 2.8 |
| NC | 3.3 | 34.4 | 29.1 | 28.9 | 13.4 | 46.9 | 43.6 | 31.9 | 7.3 | 41.7 | 41.2 | 35.9 | 7.3 | 61.9 | 79.2 | 51.5 |
| ND | 11.9 | 13.5 | 24.7 | 36.3 | 13.6 | 37 | 28.3 | 46.2 | 0 | 6.4 | 0 | 0 | 0.7 | 11.4 | 12.6 | 13.3 |
| NE | 13.1 | 24.9 | 36.2 | 40.2 | 15.7 | 23.6 | 44.2 | 63.9 | 3 | 8.5 | 0.1 | 0.1 | 4.7 | 8.5 | 5 | 7.7 |
| NH | 0.2 | 0.5 | 0.5 | 0.5 | 2.2 | 4.3 | 2.3 | 4.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| NJ | 0 | 0.7 | 1.8 | 0.7 | 0 | 0.7 | 1.8 | 0.7 | 1 | 1 | 1 | 1 | 0.6 | 0.6 | 0.6 | 0.6 |
| NM | 12.9 | 17.9 | 12.4 | 15.8 | 16.4 | 24.1 | 52.4 | 15 | 5.4 | 5.3 | 10.1 | 8.7 | 8.6 | 9.1 | 15.9 | 10.7 |
| NV | 0.2 | 0.4 | 0.4 | 0.4 | 0.3 | 4.2 | 2.7 | 2.5 | 8 | 21.5 | 17.2 | 17.6 | 27.9 | 25 | 20.9 | 20.6 |
| NY | 8.7 | 8.4 | 8.4 | 8.3 | 8.5 | 18.6 | 21.8 | 19.2 | 4.4 | 4.2 | 4.2 | 4.2 | 4.8 | 7.4 | 28.4 | 34.4 |
| OH | 9.7 | 20.4 | 19.3 | 10.9 | 30.2 | 20.3 | 30.2 | 10.5 | 4.4 | 4.6 | 4.4 | 4.4 | 8.4 | 4.5 | 4.4 | 4.4 |
| OK | 18.9 | 32.5 | 30.2 | 49.8 | 22.7 | 59.4 | 62.3 | 56.1 | 9.2 | 6.2 | 6.9 | 10.3 | 16.3 | 6.1 | 14.7 | 12.1 |
| OR | 9.1 | 9.7 | 10.8 | 5.4 | 8.5 | 12.2 | 11.9 | 16.3 | 1.6 | 1.6 | 1.6 | 1.6 | 2.8 | 8.4 | 5 | 1 |
| PA | 4.2 | 6.4 | 8.9 | 7.2 | 6.9 | 8.7 | 18.9 | 9 | 1.1 | 0.8 | 0.8 | 0.7 | 3.5 | 3.1 | 4.2 | 2.3 |
| RI | 0.9 | 0.8 | 0.8 | 0.8 | 1.2 | 1.2 | 1.2 | 1.2 | 0.3 | 0.3 | 0.3 | 0.3 | 3.3 | 3.4 | 1.4 | 2.4 |
| SC | 2.7 | 17.3 | 14.7 | 8.3 | 6.8 | 19.9 | 19.9 | 19.9 | 4.3 | 10.1 | 8.9 | 8.2 | 15.3 | 17.9 | 18 | 29.3 |
| SD | 3.3 | 9 | 9.7 | 14.4 | 5.2 | 8.3 | 13.7 | 16.8 | 0.3 | 0.1 | 0.1 | 0.1 | 1.3 | 0.1 | 0.9 | 0.8 |
| TN | 7.1 | 9.3 | 6.8 | 9.3 | 9.7 | 11.1 | 13.3 | 9.3 | 1.2 | 2.6 | 8.2 | 1.9 | 1.1 | 2.5 | 20.1 | 1.8 |
| TX | 88.9 | 109.6 | 128 | 136.6 | 110.2 | 147.9 | 164.3 | 175 | 66.8 | 116.1 | 96.1 | 109 | 120.7 | 159.4 | 163.5 | 190.2 |
| UT | 0.7 | 1 | 0.9 | 0.9 | 0.9 | 2.4 | 2 | 0.8 | 2.9 | 2.8 | 2.8 | 2.8 | 6.8 | 9.5 | 6.5 | 1.8 |
| VA | 5.7 | 18.9 | 24 | 16.4 | 14.6 | 21.6 | 29.6 | 30.8 | 16.5 | 21.7 | 20.8 | 10.8 | 35.6 | 36.3 | 45 | 17.8 |
| VT | 0.5 | 1 | 1.2 | 0.7 | 3.4 | 4.9 | 2.5 | 2.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 4.3 | 0.1 | 0.1 |
| WA | 10.4 | 15.4 | 12.3 | 15.1 | 13.6 | 26.7 | 29.7 | 19.4 | 0.4 | 0.4 | 0.4 | 0.4 | 13.1 | 0.6 | 7.2 | 6.2 |
| WI | 17.5 | 13.6 | 18.6 | 13.8 | 23.5 | 39.2 | 19.1 | 17 | 4.5 | 9.4 | 2.3 | 2.3 | 18.1 | 14.3 | 15 | 11 |
| WV | 0.9 | 0.9 | 0.9 | 0.9 | 3.4 | 0.7 | 0.7 | 0.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| WY | 19 | 26.3 | 35 | 41.9 | 20.6 | 43 | 42.9 | 48.8 | 2.3 | 0.1 | 1.1 | 0.6 | 6.7 | 0 | 2.2 | 5.6 |

# Appendix E. Transmission Value Analysis

The economic analysis presented here identifies and evaluates quantifiable benefits associated with transmission development across NTP Study zonal planning and operational analysis. The following sections outline the overall approach to quantify and regionally disaggregate the benefits of transmission applied to the NTP zonal scenarios.

## E.1 Multivalue

This analysis considers a broad range of transmission benefits including reduced capital and operating costs, reduced cost of meeting reliability requirements, and increased capture of federal and state incentives. Using outputs from the zonal production cost model, the economic analysis includes six categories of transmission benefits (Figure 42). Annualized savings for capital investments are based on the equivalent annual cost assuming a 1.7% discount rate. Transmission assets are assumed to have a 40-year asset life; all other technologies are assumed to have a 20-year asset life.

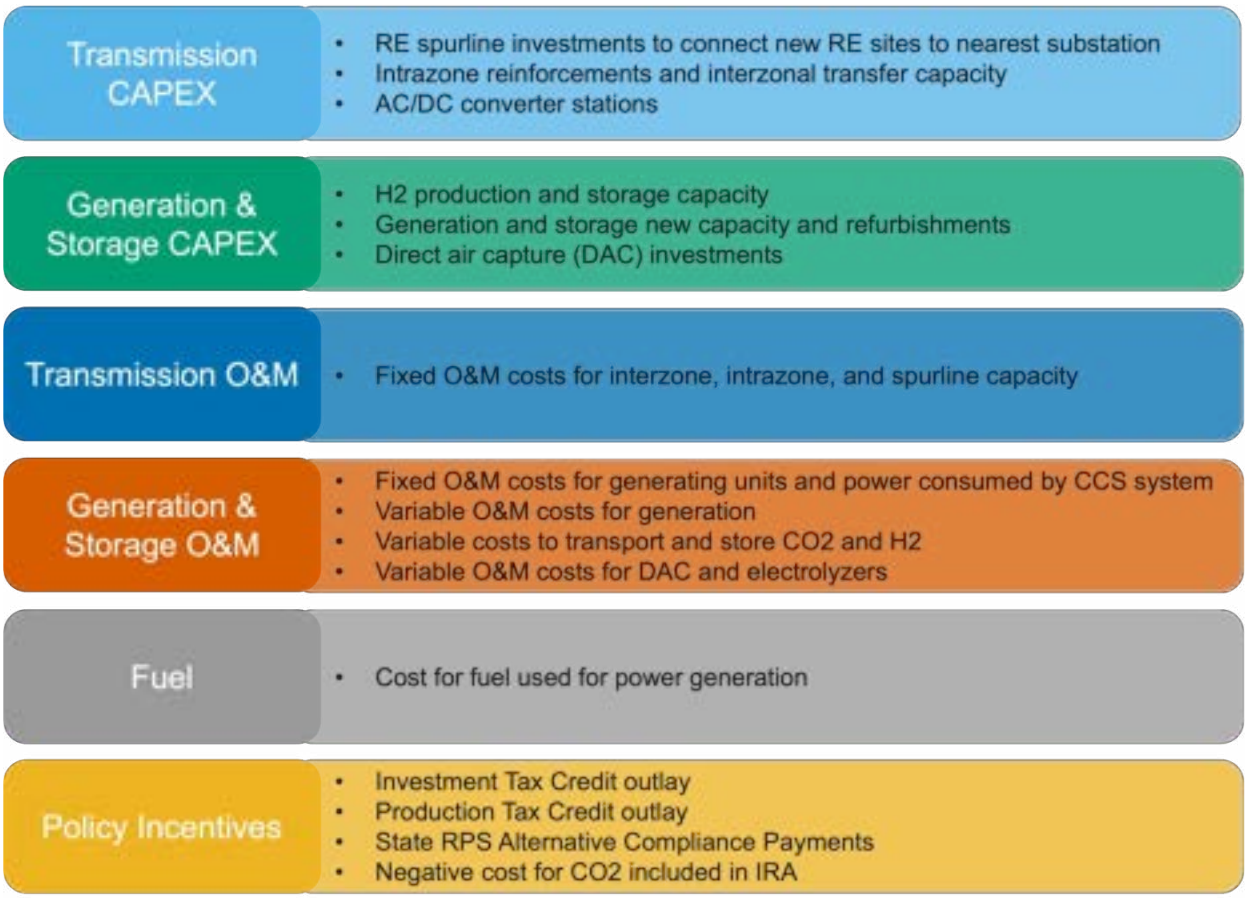



Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

## E.2 System Perspective

The NTP Study evaluates transmission investments and operations across the entire contiguous United States. The economic analysis evaluates the value of transmission across this entire system as well as to a given region (e.g., ISONE, NYISO, CAISO). The analysis does not disaggregate the benefits experienced by different types of network users within each region (e.g., generators, consumers). In addition, no assumptions about how transmission cost recovery is allocated within a region or among customer classes are made.

## E.3 Project Scope

This analysis evaluates the net benefits for the portfolio of transmission investments identified in NTP Study accelerated transmission frameworks rather than evaluating individual projects or transmission corridors. This approach reflects planning processes in place, such as MISO's multivalue project process that evaluates bundles of projects. It also aligns with the NTP Study approach, in which transmission investments and system operations are optimized on a multiregion scale. To isolate the impact of specific types of transmission development, the reference scenario (Limited) is compared with alternative "change" cases (AC, P2P, MT) that represent different types of transmission development.

## E.4 Planning Horizon

The analysis considers an almost 30-year planning horizon, covering the period 2022–2050.[53] This extended planning horizon will inform how the benefits of transmission change over time as the underlying power system changes. It is also aligned with guidance under consideration by FERC to consider system needs and changes 20+ years in the future for transmission planning.

## E.5 Uncertainty

The transmission valuation captures a range of possible future outcomes, drawing from the broad set of NTP Study sensitivity cases including macroeconomic drivers such as technology prices and availability as well as a range of system states such as different weather conditions. This analysis uses scenario-based comparisons to capture uncertainty system costs across a range of system futures.

## E.6 Regional Disaggregation: Adjusted Production Cost

As interregional transmission enables more coordinated operation of low-cost generation resources, the distribution of operating costs within each region changes. For systemwide analysis, operating costs comprise variable operation and maintenance, fuel, and startup and shutdown. These metrics are sufficient to evaluate the change in operating costs for the entire system but, when evaluating the benefit distribution among regions, a further consideration is needed to capture the

[53] 2030 is the first year in which new interregional transmission can be commissioned in the NTP Study modeling.

transmission benefits of interregional trade to each region. The adjusted production cost (APC) metric is used to evaluate these benefits. The APC is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. This metric is used among independent system operators/regional transmission operators in the United States for transmission valuation and cost allocation including SPP, MISO, and PJM and is defined as follows:

$$\text{APC} = \text{Production Cost} + \text{Purchase Costs} - \text{Generator Revenue}$$

where

$$\text{Purchase Costs} = (\text{Hourly Consumer Load} + \text{Storage Charging} + \text{Imports}) \times \text{Locational Marginal Price}$$

$$\text{Generator Revenue} = \text{Hourly Generation} \times \text{Locational Marginal Price}$$

A key benefit of the APC when trying to disaggregate transmission benefits is that it does not strictly rely on the physical location where costs are incurred to estimate costs and benefits. As a simple example, a new transmission upgrade may enable the development of low-cost generation capacity in one region (Region A) that can serve additional load in a neighboring region (Region B). Strictly looking at where costs are occurring, the new transmission line will increase capital and operating costs in Region A because it is building more capacity and generating more. By contrast, capital and operating costs will decrease in Region B because it is building less capacity and relying on imports to meet its load. However, Region A is also benefiting through increased sales of power to its neighbors. In addition, Region B is not getting these imports for free; it incurs some cost to purchase imported energy. By including an adjustment for import costs and export revenues, the APC can capture these benefits. Figure E-1 shows the production cost adjustment (change in purchase cost – generator revenue) added to the transmission value for each region and topology for the core Mid-Demand 90% by 2035 scenarios.[54]

[54] For this study, the adjusted production cost is based on zonal marginal prices from the capacity expansion model based on the marginal price of meeting capacity, energy, and policy requirements in each balancing area. The capacity expansion model represents each modeled year with 33 representative days at 4-hr resolution, for a total of 198 modeled hours. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production cost for each region.

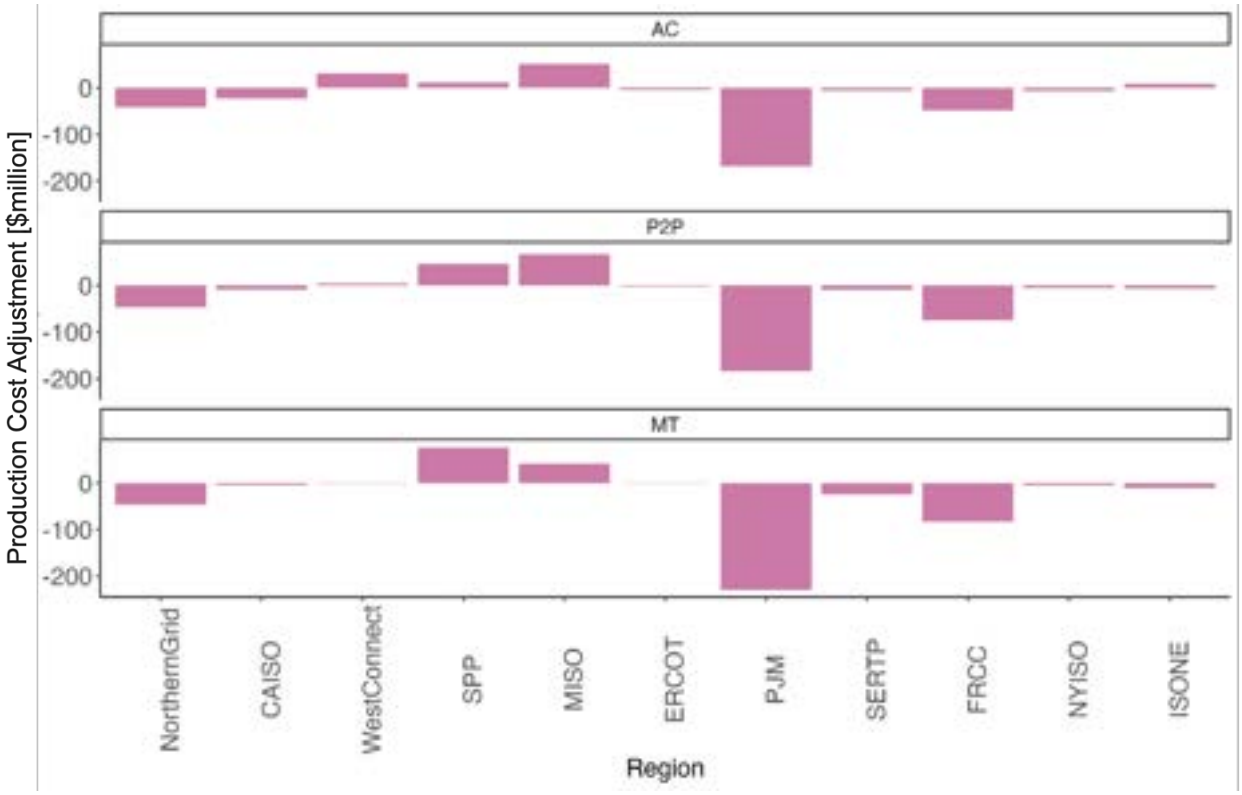



Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

# Appendix F. High Opportunity Transmission Interfaces: Regional Detail

The High Opportunity Transmission (HOT) analysis highlights robustly chosen transmission expansion opportunities for each of the 11 planning regions and each of the AC, P2P, MT transmission frameworks. The following maps show the interfaces with nearby planning regions and the 25$^{th}$ percentile of new transmission capacity built across those interfaces in the 16 sensitivity cases. These are the same data as shown in the national maps in the Text Box in Section 3.3 but provide a more granular view of transmission expansion in that planning region. The tables accompanying the maps show the 25$^{th}$ percentile as well as the 50$^{th}$ and 75$^{th}$ percentile results to inform more ambitious transmission development opportunities. Also included in the tables is the amount of existing transmission capacity across that interface. The interfaces are color coordinated to identify them in the table and map and across the other transmission framework maps. Three maps and associated tables are shown for each region showing the AC, P2P, and MT frameworks in that order. Some regions are grouped together when they have common borders (e.g., SERTP and FRCC; NYISO and ISONE).

## CAISO

### AC Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| Northern Grid S. | 11 | 0.1 | 0.7 | 1.4 |
| West Connect S. | 5.3 | 3.6 | 4.0 | 4.7 |

### P2P Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| Northern Grid S. | 11 | 0 | 0.1 | 0.4 |
| West Connect S. | 5.3 | 3.0 | 4.1 | 4.9 |

### MT Framework

**Interface Capacity (GW)**

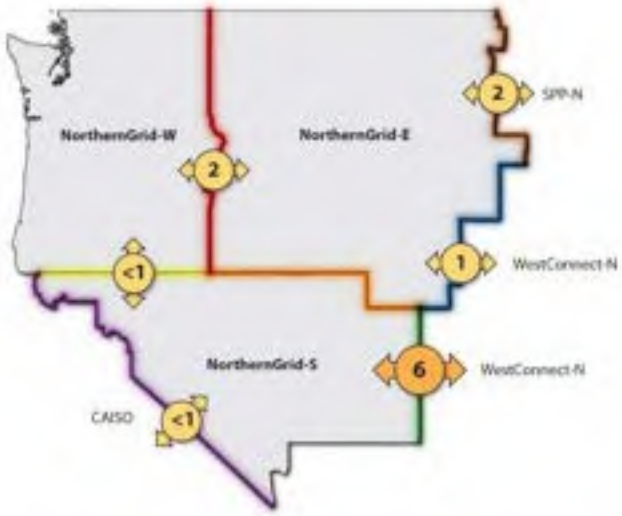
| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| Northern Grid S. | 11 | 0 | 0.4 | 0.6 |
| West Connect S. | 5.3 | 6.2 | 6.8 | 9.1 |

## NorthernGrid

### AC Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NG-W, NG-E | 13.2 | 1.7 | 1.7 | 1.7 |
| NG-E, SPP-N | 0.2 | 0 | 0 | 0 |
| NG-E, WC-N | 4.0 | 1.1 | 1.2 | 1.8 |
| NG-E, NG-S | 3.1 | 0 | 0 | 0.6 |
| NG-W, NG-S | 0.5 | 0.1 | 0.4 | 1.2 |
| NG-S, WC-N | 2.4 | 6.3 | 7.1 | 7.2 |
| NG-S, CAISO | 11 | 0.1 | 0.7 | 1.4 |




### P2P Framework

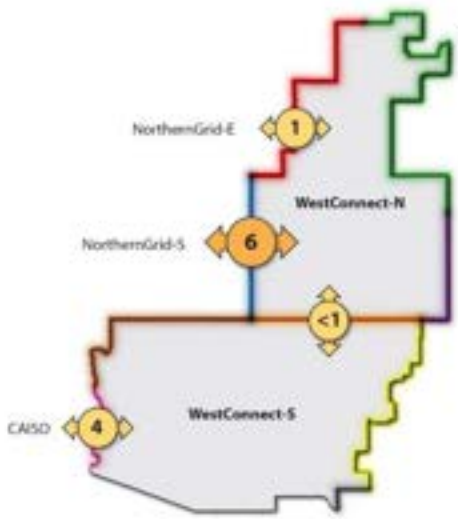
**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NG-W, NG-E | 13.2 | 1.7 | 1.7 | 1.7 |
| NG-E, SPP-N | 0.2 | 1.8 | 2.2 | 2.5 |
| NG-E, WC-N | 4.0 | 1.4 | 2.1 | 2.5 |
| NG-E, NG-S | 3.1 | 0 | 0 | 0 |
| NG-W, NG-S | 0.5 | 0.1 | 0.3 | 0.5 |
| NG-S, WC-N | 2.4 | 5.8 | 7.0 | 7.9 |
| NG-S, CAISO | 11 | 0.1 | 0.4 | 0.3 |

### MT Framework

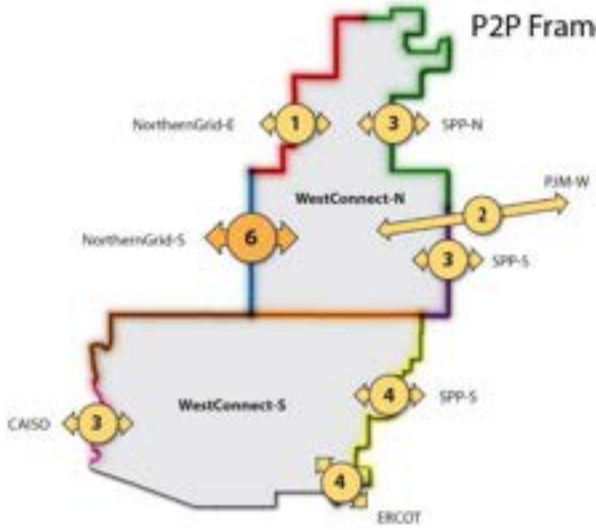
**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NG-W, NG-E | 13.2 | 1.7 | 1.7 | 1.7 |
| NG-E, SPP-N | 0.2 | 1.2 | 1.8 | 2.1 |
| NG-E, WC-N | 4.0 | 3.9 | 5.0 | 5.7 |
| NG-E, NG-S | 3.1 | 2.0 | 2.6 | 3.9 |
| NG-W, NG-S | 0.5 | 0.2 | 0.5 | 1.2 |
| NG-S, WC-N | 2.4 | 6.0 | 6.4 | 6.7 |
| NG-S, CAISO | 11 | 0 | 0.4 | 0.6 |



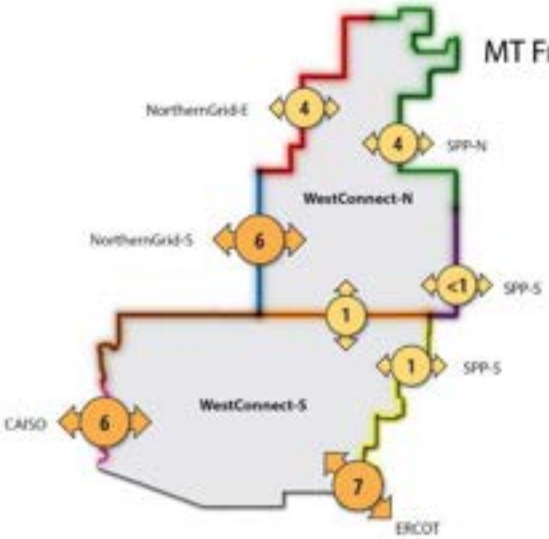

Interface Capacity (GW)

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| WC-N, NG-E | 4.0 | 1.1 | 1.2 | 1.8 |
| WC-N, NG-S | 2.4 | 6.3 | 7.1 | 7.2 |
| WC-N, SPP-N | 0.5 | 0 | 0 | 0 |
| WC-N, SPP-S | 0.2 | 0 | 0 | 0 |
| WC-N, WC-S | 1.4 | 0.1 | 0.7 | 0.8 |
| WC-S, NG-S | 7.3 | 0 | 0 | 0 |
| WC-S, SPP-S | 0.4 | 0 | 0 | 0 |
| WC-S, ERCOT | 0 | 0 | 0 | 0 |
| WC-S, CAISO | 5.3 | 3.6 | 4.0 | 4.7 |




Interface Capacity (GW)

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| WC-N, NG-E | 4.0 | 1.4 | 2.1 | 2.5 |
| WC-N, NG-S | 2.4 | 5.8 | 7.0 | 7.9 |
| WC-N, SPP-N | 0.5 | 2.6 | 3.1 | 3.9 |
| WC-N, SPP-S | 0.2 | 2.7 | 3.1 | 3.9 |
| WC-N, WC-S | 1.4 | 0 | 0.1 | 0.3 |
| WC-S, NG-S | 7.3 | 0 | 0 | 0 |
| WC-S, SPP-S | 0.4 | 4.2 | 5.7 | 6.5 |
| WC-S, ERCOT | 0 | 4.1 | 5.7 | 7.3 |
| WC-S, CAISO | 5.3 | 3.0 | 4.1 | 4.9 |

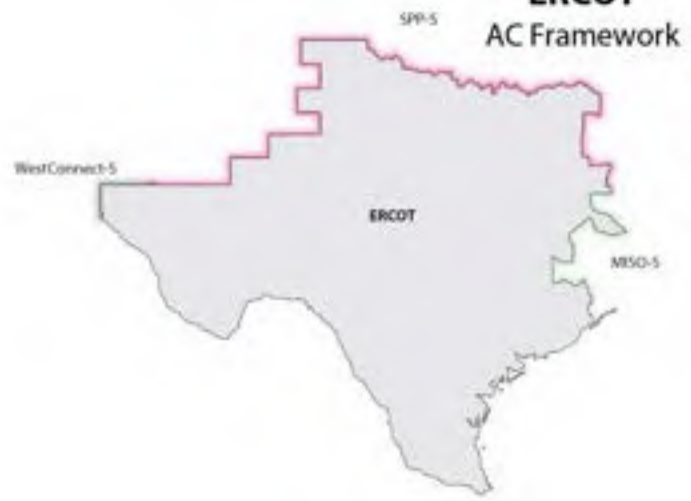



Interface Capacity (GW)

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| WC-N, NG-E | 4.0 | 3.9 | 5.0 | 5.7 |
| WC-N, NG-S | 2.4 | 6.0 | 6.4 | 6.7 |
| WC-N, SPP-N | 0.5 | 3.9 | 5.4 | 6.6 |
| WC-N, SPP-S | 0.2 | 0.5 | 0.9 | 1.5 |
| WC-N, WC-S | 1.4 | 1.0 | 1.6 | 2.4 |
| WC-S, NG-S | 7.3 | 0 | 0 | 0 |
| WC-S, SPP-S | 0.4 | 1.4 | 1.9 | 3.7 |
| WC-S, ERCOT | 0 | 6.5 | 7.1 | 9.5 |
| WC-S, CAISO | 5.3 | 6.2 | 6.8 | 9.1 |

## ERCOT

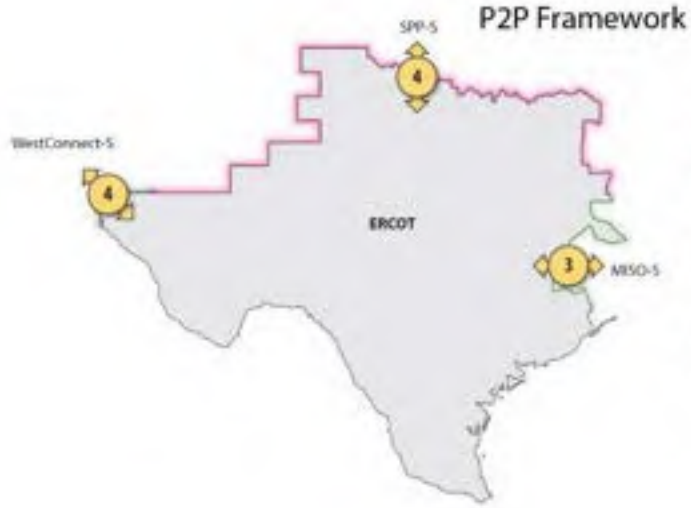
### AC Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| ERCOT, SPP-S | 0.8 | 0 | 0 | 0 |
| ERCOT, WC-S | 0 | 0 | 0 | 0 |
| ERCOT, MISO-S | 0 | 0 | 0 | 0 |

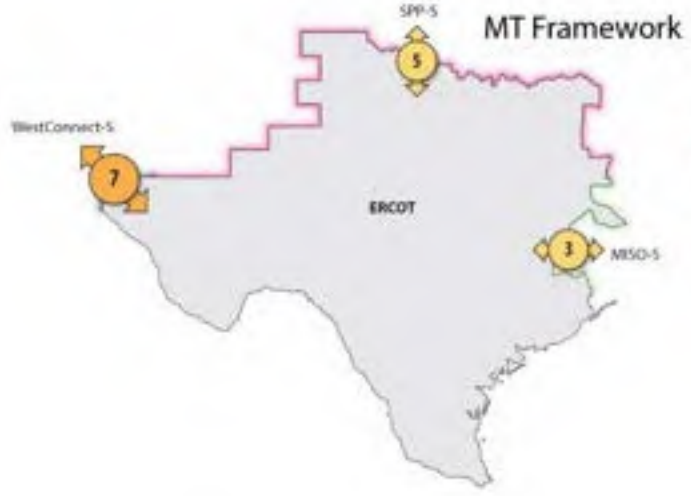
### P2P Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| ERCOT, SPP-S | 0.8 | 4.1 | 5.1 | 5.7 |
| ERCOT, WC-S | 0 | 4.1 | 5.7 | 7.3 |
| ERCOT, MISO-S | 0 | 3.3 | 4.4 | 4.9 |
| **Nonadjacent Region Interfaces** | | | | |
| ERCOT, MISO-N | 0 | 0 | 0.2 | 1.3 |
| ERCOT, NG-S | 0 | 0 | 0 | 0.4 |
| ERCOT, SPP-N | 0 | 0 | 0 | 0.2 |
| ERCOT, WC-N | 0 | 0 | 0 | 0.3 |

### MT Framework

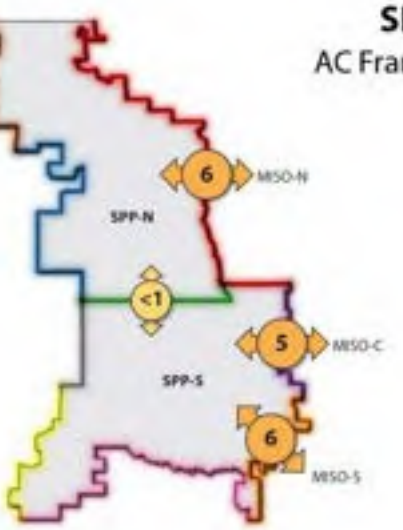



**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| ERCOT, SPP-S | 0.8 | 4.9 | 6.3 | 12 |
| ERCOT, WC-S | 0 | 6.5 | 7.1 | 9.5 |
| ERCOT, MISO-S | 0 | 2.6 | 3.7 | 4.6 |

## SPP

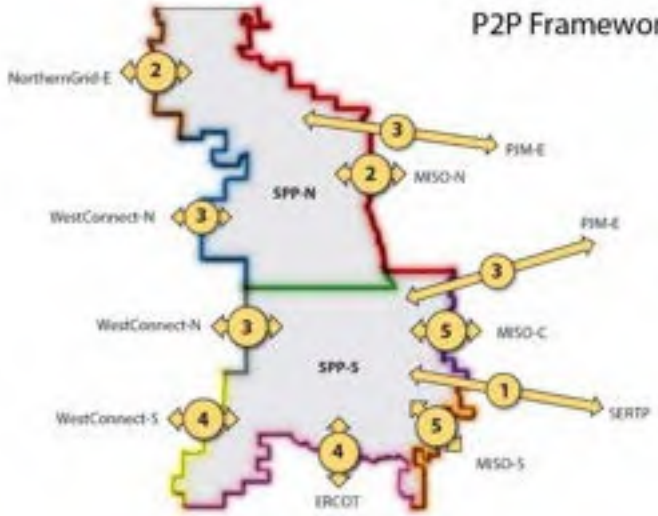
### AC Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SPP-N, NG-E | 0.2 | 0 | 0 | 0 |
| SPP-N, MISO-N | 10.0 | 6.0 | 7.6 | 9.4 |
| SPP-N, WC-N | 0.5 | 0 | 0 | 0 |
| SPP-N, SPP-S | 5.4 | 0.2 | 0.3 | 0.4 |
| SPP-S, MISO-C | 2.0 | 4.7 | 6.0 | 6.0 |
| SPP-S, MISO-S | 3.3 | 5.8 | 6.4 | 7.0 |
| SPP-S, WC-N | 0.2 | 0 | 0 | 0 |
| SPP-S, WC-S | 0.4 | 0 | 0 | 0 |
| SPP-S, ERCOT | 0.8 | 0 | 0 | 0 |

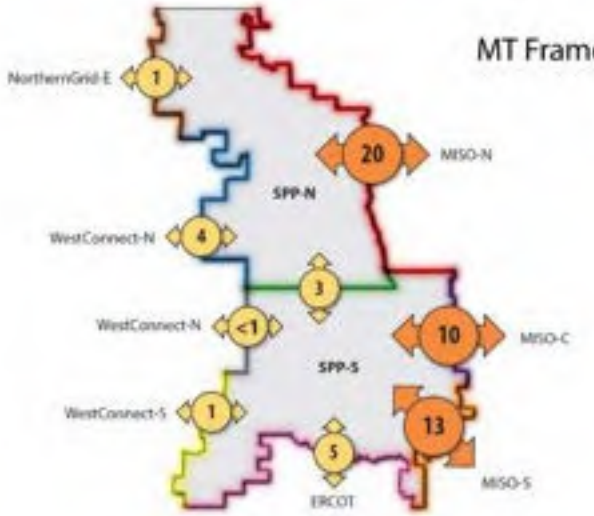
### P2P Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SPP-N, NG-E | 0.2 | 1.8 | 2.2 | 2.5 |
| SPP-N, MISO-N | 10.0 | 1.7 | 2.6 | 3.8 |
| SPP-N, WC-N | 0.5 | 2.6 | 3.1 | 3.9 |
| SPP-N, SPP-S | 5.4 | 0 | 0.2 | 0.7 |
| SPP-S, MISO-C | 2.0 | 4.8 | 5.6 | 5.8 |
| SPP-S, MISO-S | 3.3 | 4.5 | 5.5 | 6.3 |
| SPP-S, WC-N | 0.2 | 2.7 | 3.1 | 3.9 |
| SPP-S, WC-S | 0.4 | 4.2 | 5.7 | 6.5 |
| SPP-S, ERCOT | 0.8 | 4.1 | 5.1 | 5.7 |
| **Nonadjacent Region Interfaces** | | | | |
| SPP-N, PJM-E | 0 | 3.4 | 5.2 | 10 |
| SPP-S, PJM-E | 0 | 3.3 | 4.7 | 7.1 |
| SPP-S, SRTP | 0 | 1.0 | 2.5 | 4.6 |

### MT Framework

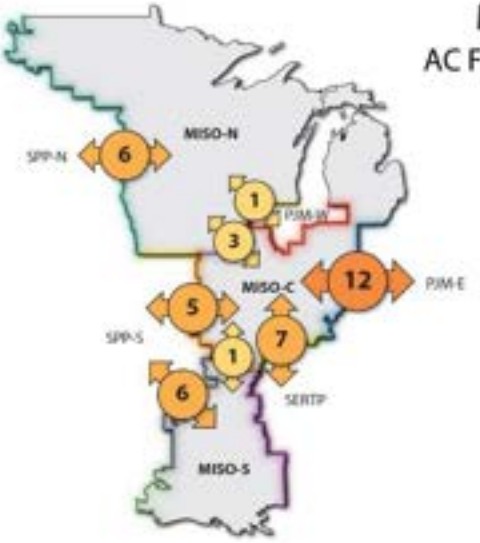



**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SPP-N, NG-E | 0.2 | 1.2 | 1.8 | 2.1 |
| SPP-N, MISO-N | 10.0 | 20.3 | 24.8 | 27.8 |
| SPP-N, WC-N | 0.5 | 3.9 | 5.4 | 6.6 |
| SPP-N, SPP-S | 5.4 | 3.4 | 5.8 | 7.5 |
| SPP-S, MISO-C | 2.0 | 9.9 | 13.8 | 16.8 |
| SPP-S, MISO-S | 3.3 | 12.4 | 16.5 | 18.1 |
| SPP-S, WC-N | 0.2 | 0.5 | 0.9 | 1.5 |
| SPP-S, WC-S | 0.4 | 1.4 | 1.9 | 3.7 |
| SPP-S, ERCOT | 0.8 | 4.9 | 6.3 | 12.0 |

## MISO

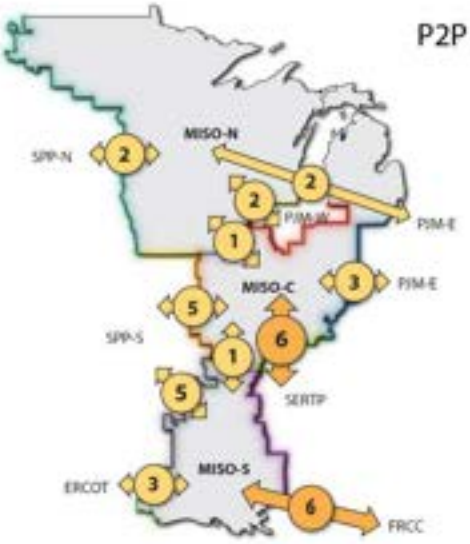
### AC Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| MISO-N, SPP-N | 10.0 | 6.0 | 7.6 | 9.4 |
| MISO-N, PJM-W | 5.0 | 1.4 | 2.9 | 4.9 |
| MISO-N, MISO-C | 5.5 | 2.6 | 4.3 | 5.1 |
| MISO-C, PJM-W | 15.1 | 0 | 0.7 | 1.0 |
| MISO-N, SPP-S | 1.1 | 0 | 0 | 0 |
| MISO-C, PJM-E | 28.3 | 11.7 | 14.4 | 16.1 |
| MISO-C, SPP-S | 2.0 | 4.7 | 6.0 | 6.0 |
| MISO-C, SERTP | 4.1 | 7.5 | 10.1 | 12.2 |
| MISO-C, MISO-S | 2.1 | 1.4 | 1.8 | 2.3 |
| MISO-S, SPP-S | 3.3 | 5.8 | 6.4 | 7.0 |
| MISO-S, SERTP | 11.0 | 0 | 0 | 0.1 |
| MISO-S, ERCOT | 0 | 0 | 0 | 0 |

### P2P Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| MISO-N, SPP-N | 10.0 | 1.7 | 2.6 | 3.8 |
| MISO-N, PJM-W | 5.0 | 1.5 | 2.0 | 3.4 |
| MISO-N, MISO-C | 5.5 | 1.0 | 1.8 | 4.3 |
| MISO-C, PJM-W | 15.1 | 0 | 0 | 0 |
| MISO-N, SPP-S | 1.1 | 0 | 0 | 0 |
| MISO-C, PJM-E | 28.3 | 2.6 | 4.7 | 7.9 |
| MISO-C, SPP-S | 2.0 | 4.8 | 5.6 | 5.8 |
| MISO-C, SERTP | 4.1 | 5.6 | 6.8 | 7.7 |
| MISO-C, MISO-S | 2.1 | 1.2 | 1.8 | 2.7 |
| MISO-S, SPP-S | 3.3 | 4.5 | 5.5 | 6.3 |
| MISO-S, SERTP | 11.0 | 0 | 0 | 0 |
| MISO-S, ERCOT | 0 | 3.3 | 4.4 | 4.9 |
| Nonadjacent Region Interfaces: MISO-N, PJM-E | 0 | 2.0 | 4.4 | 7.1 |
| Nonadjacent Region Interfaces: MISO-S, FRCC | 0 | 6.2 | 7.3 | 8.6 |

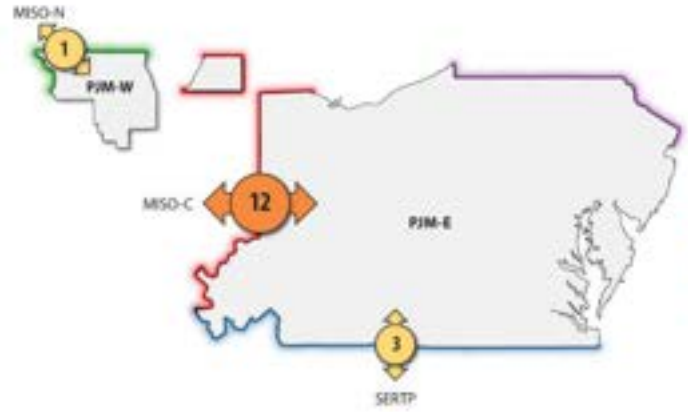
### MT Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25TH | 50TH | 75TH |
|---|---|---|---|---|
| MISO-N, SPP-N | 10.0 | 20.3 | 24.8 | 27.8 |
| MISO-N, PJM-W | 5.0 | 21.8 | 23.4 | 27.5 |
| MISO-N, MISO-C | 5.5 | 3.8 | 5.0 | 5.5 |
| MISO-C, PJM-W | 15.1 | 16.5 | 19.7 | 22.8 |
| MISO-N, SPP-S | 1.1 | 0 | 0 | 0.1 |
| MISO-C, PJM-E | 28.3 | 24.7 | 28.0 | 32.6 |
| MISO-C, SPP-S | 2.0 | 9.9 | 13.8 | 16.8 |
| MISO-C, SERTP | 4.1 | 7.2 | 9.3 | 12.5 |
| MISO-C, MISO-S | 2.1 | 0.7 | 1.3 | 2.3 |
| MISO-S, SPP-S | 3.3 | 12.4 | 16.5 | 18.1 |
| MISO-S, SERTP | 11.0 | 5.8 | 9.7 | 11.1 |
| MISO-S, ERCOT | 0 | 2.6 | 3.7 | 4.6 |

## PJM

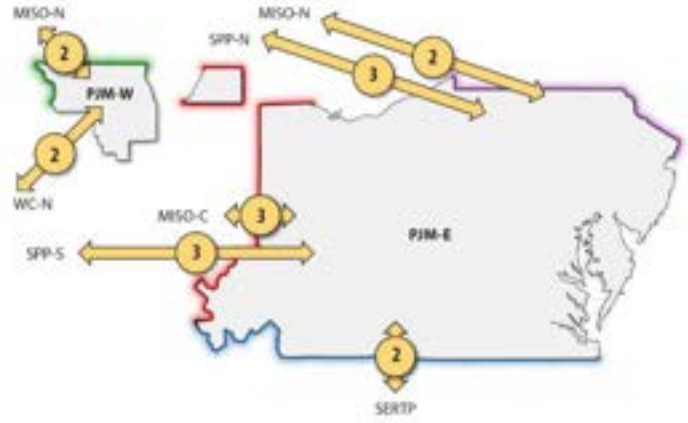
### AC Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| PJM-W, MISO-N | 5.0 | 1.4 | 2.9 | 4.9 |
| PJM-E, MISO-C | 28.3 | 11.7 | 14.4 | 16.1 |
| PJM-E, SERTP | 10.9 | 3.2 | 6.8 | 7.4 |
| PJM-E, NYISO | 6.6 | 0 | 0 | 0 |

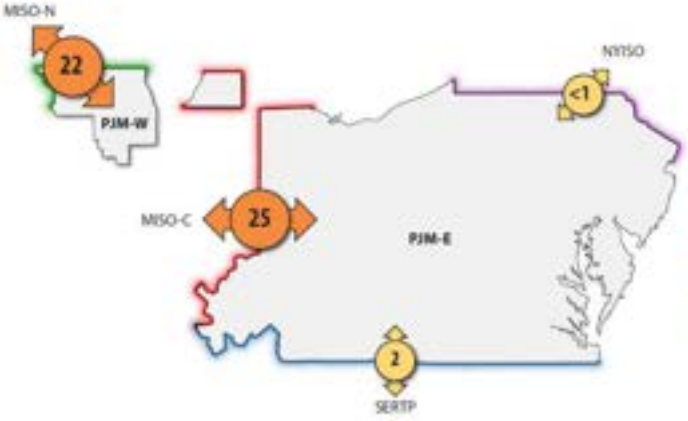
### P2P Framework




**Interface Capacity (GW)**

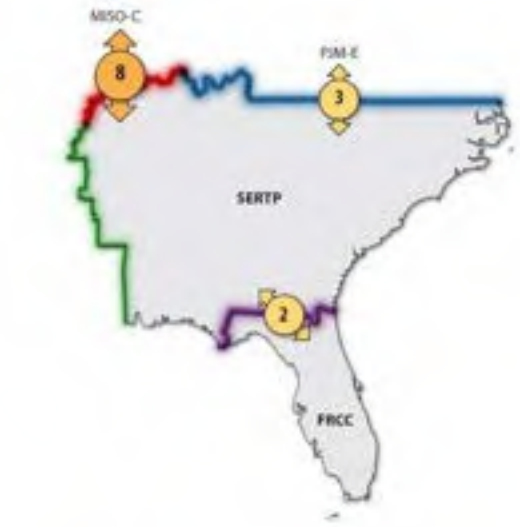
| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| PJM-W, MISO-N | 5.0 | 1.5 | 2.0 | 3.4 |
| PJM-E, MISO-C | 28.3 | 2.6 | 4.7 | 7.9 |
| PJM-E, SERTP | 10.9 | 2.2 | 5.0 | 6.3 |
| PJM-E, NYISO | 6.6 | 0 | 0 | 0 |
| **Nonadjacent Region Interfaces** | | | | |
| PJM-E, MISO-N | 0 | 2.0 | 4.4 | 7.1 |
| PJM-E, SPP-N | 0 | 3.4 | 5.2 | 10.0 |
| PJM-E, SPP-S | 0 | 3.3 | 4.7 | 7.1 |
| PJM-W, WC-N | 0 | 2.2 | 3.1 | 4.9 |

### MT Framework




**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| PJM-W, MISO-N | 5.0 | 21.8 | 23.4 | 27.5 |
| PJM-E, MISO-C | 28.3 | 24.7 | 28.0 | 32.6 |
| PJM-E, SERTP | 10.9 | 1.6 | 3.8 | 5.7 |
| PJM-E, NYISO | 6.6 | 0.9 | 2.4 | 3.7 |

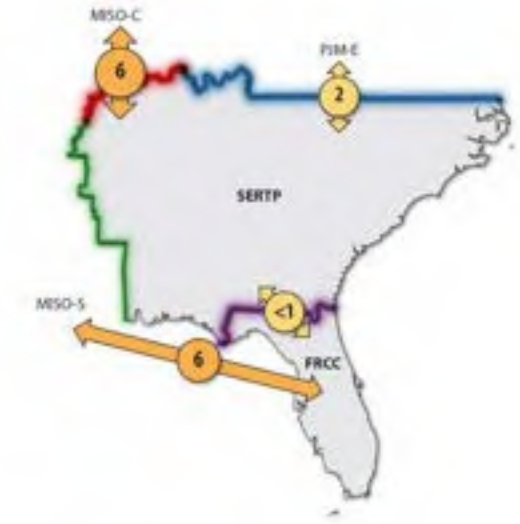



## SERTP & FRCC

### AC Framework

**Interface Capacity (GW)**

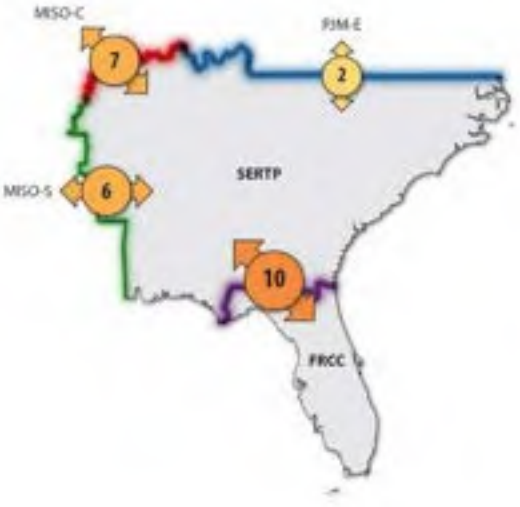
| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SERTP, MISO-C | 4.1 | 7.5 | 10.1 | 12.2 |
| SERTP, PJM-E | 10.9 | 3.2 | 6.8 | 7.4 |
| SERTP, MISO-S | 11.0 | 0 | 0 | 0.1 |
| SERTP, FRCC | 6.6 | 1.9 | 2.3 | 2.6 |




### P2P Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SERTP, MISO-C | 4.1 | 5.6 | 6.8 | 7.7 |
| SERTP, PJM-E | 10.9 | 2.2 | 5.0 | 6.3 |
| SERTP, MISO-S | 11.0 | 0 | 0 | 0 |
| SERTP, FRCC | 6.6 | 0.1 | 0.8 | 1.7 |
| **Nonadjacent Region Interfaces** | | | | |
| FRCC, MISO-S | 6.9 | 6.2 | 7.3 | 8.6 |




### MT Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| SERTP, MISO-C | 4.1 | 7.2 | 9.3 | 12.5 |
| SERTP, PJM-E | 10.9 | 1.6 | 3.8 | 5.7 |
| SERTP, MISO-S | 11.0 | 5.8 | 9.7 | 11.1 |
| SERTP, FRCC | 6.6 | 10.1 | 11.7 | 12.4 |

## NYISO & ISONE

### AC Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NYISO, ISONE | 3.5 | 1.7 | 1.8 | 2.5 |
| NYISO, PJM-E | 6.6 | 0 | 0 | 0 |

### P2P Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NYISO, ISONE | 3.5 | 1.4 | 1.9 | 2.4 |
| NYISO, PJM-E | 6.6 | 0 | 0 | 0 |

### MT Framework

**Interface Capacity (GW)**

| REGION | EXISTING | Percentile of New Capacity 25th | 50th | 75th |
|---|---|---|---|---|
| NYISO, ISONE | 3.5 | 1.6 | 2.2 | 2.9 |
| NYISO, PJM-E | 6.6 | 0.9 | 2.4 | 3.7 |

DOE/GO-102024-6258 | October 2024

# National Transmission Planning Study

## Chapter 3:

# Transmission Portfolios and Operations for 2035 Scenarios

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

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# Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios (this chapter)** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# List of Acronyms

| | |
|---|---|
| ADS | Anchor Dataset |
| AC | alternating current |
| AFUDC | allowance for funds used during construction |
| ATB | Annual Technology Baseline |
| EI | Eastern Interconnection |
| BA | balancing authority |
| BASN | Basin (WECC Region) |
| B2B | back-to-back |
| BESS | battery energy storage systems |
| BLM | Bureau of Land Management |
| CAISO | California Independent System Operator |
| CALN | Northern California (WECC region) |
| CALS | Southern California (WECC region) |
| CC | combined cycle |
| CCS | carbon capture and storage |
| CEM | Capacity Expansion Model |
| CEMS | continuous emission monitoring system |
| CONUS | contiguous United States |
| DC | direct current |
| DOE | U.S. Department of Energy |
| DSW | Desert Southwest (WECC region) |
| EER | Evolved Energy Research |
| EI | Eastern Interconnection |
| EIA | U.S. Energy Information Administration |

| | |
|---|---|
| EIPC | Eastern Interconnection Planning Collaborative |
| EHV | extra high voltage (>500 kV) |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| EPE | Empresa de Pesquisa Energética |
| ERAG | Eastern Interconnection Reliability Assessment Group |
| ERCOT | Electric Reliability Council of Texas |
| FRCC | Florida Reliability Coordinating Council |
| GT | gas turbine |
| GW | gigawatt |
| HV | high voltage (230 kV ≥ V > 500 kV) |
| HVAC | high-voltage alternating current |
| HVDC | high-voltage direct current |
| IBR | inverter-based resource |
| ISO | independent system operator |
| ISONE | Independent System Operator of New England |
| ITC | investment tax credit |
| km | kilometer |
| kV | kilovolt |
| LCC | line-commutated converter |
| LCOE | levelized cost of energy |
| LPF | load participation factor |
| MISO | Midcontinent Independent System Operator |
| MMWG | Multiregion Modeling Working Group |
| MT | multiterminal |
| MVA | megavolt ampere |

| | |
|---|---|
| MW | megawatt |
| NARIS | North American Renewable Integration Study |
| NERC | North American Electric Reliability Corporation |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| NWUS-E | Northwest U.S. West (WECC region) |
| NWUS-W | Northwest U.S. East (WECC Region) |
| NYISO | New York Independent System Operator |
| PCM | production cost model |
| POI | point of interconnection |
| PPA | power purchase agreement |
| PTC | production tax credit |
| PV | photovoltaic |
| R&D | research and development |
| ReEDS | Regional Energy Deployment System (model) |
| reV | Renewable Energy Potential (model) |
| ROCK | Rocky Mountain (WECC Region) |
| ROW | right of way |
| SERTP | Southeastern Regional Transmission Planning |
| SPP | Southwest Power Pool |
| TI | Texas Interconnection |
| TRC | technical review committee |
| TWh | terawatt-hour |
| TW-miles | terawatt-miles |
| VSC | voltage source converter |

| | |
|---|---|
| VRE | variable renewable energy |
| WECC | Western Electricity Coordinating Council |
| WG | Working Group |
| WI | Western Interconnection |
| Z2N | zonal-to-nodal |

# Chapter 3 Overview

The National Transmission Planning Study (NTP Study) evaluates the role and value of transmission for the contiguous United States. The development and verification of transmission portfolios is a critical aspect of the analysis that allows transformative scenarios to be tested against network and operational constraints. This chapter presents the methods for developing the transmission portfolios, the resulting portfolios for the contiguous United States, and alternative portfolios for the Western Interconnection used for focused studies in Chapters 4 and 5 as well as additional insights about how these transmission portfolios are used in hourly operations for a future model year of 2035. The chapter also describes an evaluation of the benefits and costs of transmission for the alternative Western Interconnection portfolios.

The transmission portfolio analysis adopts a subset of future scenarios from the capacity expansion modeling (Regional Energy Deployment System [ReEDS] scenarios; Chapter 2) to translate into nodal production cost and linearized direct current (DC) power flow models. The process for translating from zonal ReEDS scenarios to nodal models required the integration of industry planning power flow cases for each interconnection. The generation and storage capacities from the ReEDS scenarios were strictly adopted. However, given the additional constraints of planning transmission in a detailed network model, the ReEDS transmission capacities and zonal connections were guidelines in the transmission planning stage. The resulting transmission portfolios reflect the general trends from the ReEDS scenarios. In addition, given the broad possibilities of a transmission portfolio for the entire contiguous United States, the focus of the transmission buildout started with interregional needs, followed by other high-voltage intraregional transfers and local needs.

The three ReEDS scenarios adopted for the zonal-to-nodal translation are shown in Table I. These scenarios represent central assumptions from the full set of 96 ReEDS scenarios, representing the Mid-Demand, 90% by 2035 decarbonization, and central technology costs for the three transmission frameworks.

Table I. Summary of Scenarios for Zonal-to-Nodal Translation

| Dimension | Limited | AC | MT-HVDC |
|---|---|---|---|
| Transmission framework[1] | AC expansion within transmission planning regions | AC expansion within interconnects | HVDC expansion across interconnects (+AC within transmission planning regions) |
| Model year | 2035 | | |
| Annual electricity demand | Mid Demand[1]<br>CONUS: 5620 TWh (916 GW)<br>Western Interconnection: 1097 TWh (186 GW)<br>ERCOT: 509 TWh (93 GW)<br>Eastern Interconnection: 4014 TWh (665 GW) | | |
| $CO_2$ emissions target | CONUS: 90% reduction by 2035 (relative to 2005) | | |

[1] *See Chapter 2 for further details.*

*$CO_2$ = carbon dioxide; AC = alternating current; TWh = terawatt-hour; GW = gigawatt; HVDC = high-voltage direct current*

The resulting transmission portfolios developed for the nodal analysis represent one of many possible network expansions that meet the needs of the zonal scenarios. Figures I through III show the three portfolios developed for the contiguous United States. The vast differences between transmission portfolios that all reach a 90% reduction in emissions by 2035 demonstrate that transmission can enable multiple pathways to decarbonization. In addition, all transmission portfolios demonstrate intraregional networks as an important component of expansion and high-voltage networks to collect renewable energy in futures with high amounts of wind and solar.

Figure I. Transmission portfolio for the Limited scenario for model year 2035

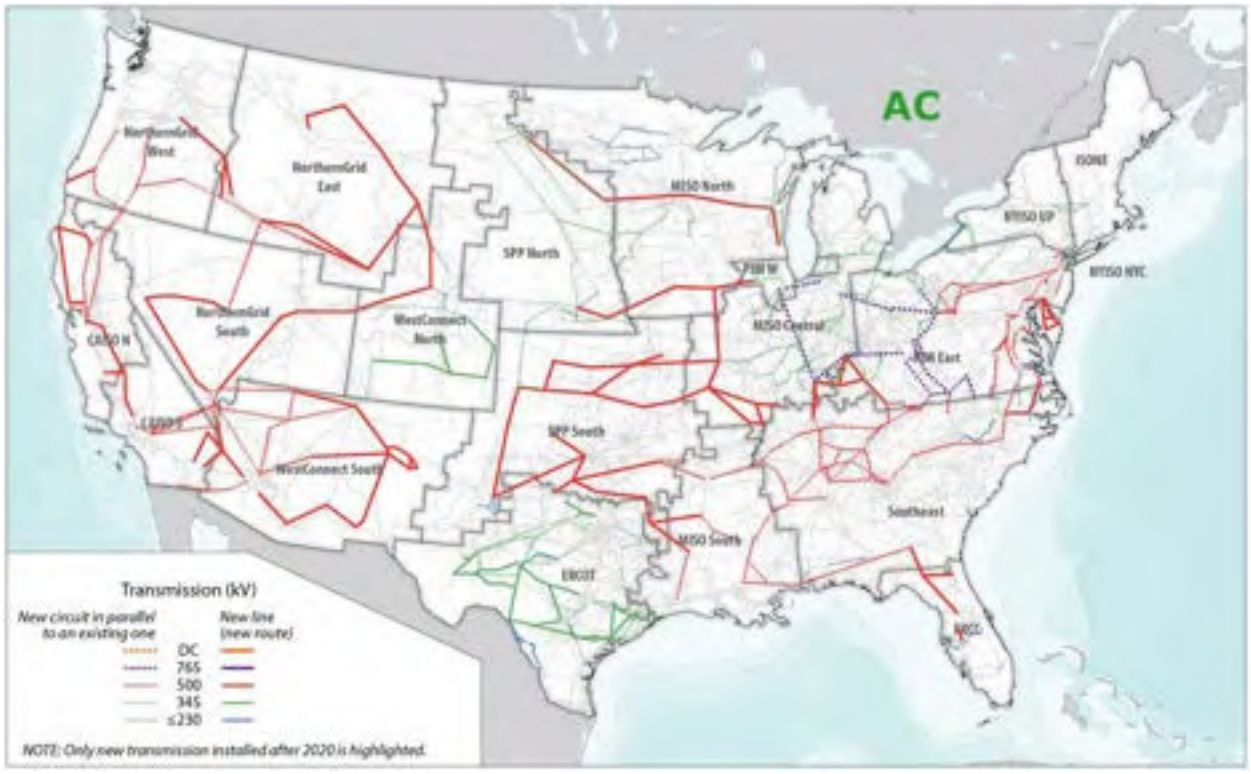


Figure II. Transmission portfolio for the AC scenario for model year 2035

*AC = alternating current*

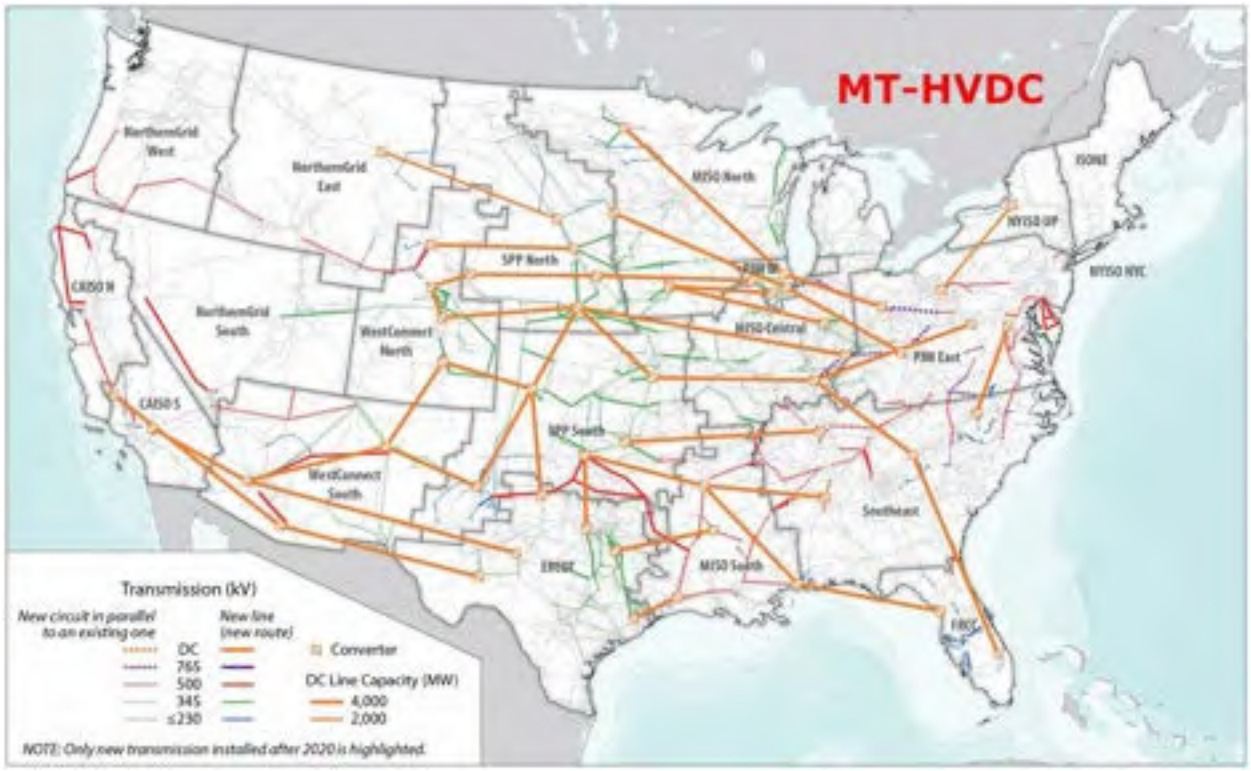


Figure III. Transmission portfolio for the MT-HVDC scenario for the model year 2035

*MT = multiterminal; HVDC = high-voltage direct current*

The production cost modeling of the scenarios demonstrates the addition of substantial amounts of interregional transmission provides significant opportunities and challenges for grid operators. For example, most regions rely on imports or exports in all three scenarios, but across almost all regions, the alternating current (AC) and multiterminal (MT) high-voltage direct current (HVDC) transmission scenarios lead to more overall energy exchange. More specifically, 19% of the total energy consumed in the Limited scenario flows over interregional transmission lines whereas that number increases to 28% in AC and 30% in the MT-HVDC scenario.

The analysis of the Western Interconnection examines how flows around the West change in response to high levels of renewable energy and transmission. In the AC and MT-HVDC scenarios, there is more variation on the interregional transmission lines, including larger swings diurnally. The patterns of flow are impacted by the generation from solar and the role storage plays in meeting peak demand. On average, the Limited scenario relies on more storage generation during the peak than the AC and MT-HVDC scenarios. In addition, the MT-HVDC scenario also imports across the HVDC lines connecting the Eastern Interconnection to balance the availability of generation in the West, which reduces the need for peaking storage.

The methods developed for the transmission portfolio analysis are novel in that they could be applied on a large geographic scale and include both production cost modeling and rapid DC-power-flow-informed transmission expansions. The incorporation of capacity expansion modeling data was also innovative. This is not the first example of

closely linking capacity expansion modeling to production cost and power flow models in industry or the research community. However, several advancements were made to realistically capture the various network points of interconnection for large amounts of wind and solar, build out the local collector networks if necessary, and validate the interregional portfolios that might arise from scenarios that reach 90% reduction in emissions by 2035.

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# 1 Introduction

The transmission system is a critical part of the electric power system that requires detailed planning to ensure safe and reliable operations of the grid. A cornerstone of power system planning for decades is nodal modeling and analysis. Nodal power system models consist of the specific components of the system, such as generators, loads, and transmission lines in mathematical representations to use for analysis and simulation. To adequately evaluate the role and value of transmission for the contiguous United States (CONUS), the National Transmission Planning Study (NTP Study) uses nodal models for various analyses regarding power system planning and reliability. The use of the nodal models in the NTP Study is part of a broader framework that applies multiple models and integrates aspects of reliability and economics to evaluate how transmission can help meet the needs of future systems. This chapter details the methods for compiling detailed nodal models of the contiguous U.S. power system and using this dataset to build transmission portfolios for the future as well as the operational insights from production cost modeling of future U.S. grids.

Modeling the entire contiguous U.S. electricity system at a nodal level serves two primary objectives: 1) it verifies the feasibility of future power systems that can meet the physical constraints that dictate operations and 2) it provides insights on grid balancing that match the temporal and spatial granularity with which grid operators view the system. Table 1 further defines several subobjectives of nodal modeling. To achieve these objectives, the study team combined industry planning models with several scenarios adopted from zonal modeling of the CONUS using the Regional Energy Deployment System (ReEDS) model, detailed in Chapter 2.[2] These future scenarios are translated into nodal models by combining existing network details with plans for generation, storage, and transmission. The result of this “zonal-to-nodal” (Z2N) translation is a detailed nodal model of a future electric power system of the United States. This resulting nodal model includes unit-level generation and node-to-node transmission components, among many other details of the physical assets on the grid.

In the process of creating nodal models of the future, transmission portfolios are developed that meet the needs of the power system and the intent of the scenario. The development and verification of the transmission portfolios is a critical aspect of the analysis that allows transformative scenarios to be tested against network and operational constraints. The nodal models, inclusive of transmission portfolios, produced with this exercise are used across multiple modeling efforts of the NTP Study, some of which are detailed in Chapters 4 and 5 of this report.

Section 2 of this chapter presents the methods of the Z2N translation and the process to plan the transmission portfolios. Section 3 presents the resulting transmission portfolios of the contiguous United States for three scenarios for the model year 2035 and hourly

[2] The ReEDS model contains 134 zones comprising the contiguous U.S. electricity system. ReEDS finds the least-cost mix of generation, storage, and transmission to balance load and supply given various technical, policy, and cost constraints for a set of years into the future. Chapter 2 details the long-term planning scenarios developed with ReEDS, which is focused on the years out to 2050.

operational insights. Section 4 presents analysis of the Western Interconnection of the United States, including alternative transmission portfolios and operations, for a similar set of scenarios in addition to an economic comparison of the investment and operations of the scenarios from this section. Conclusions and potential future work are discussed in Section 5.

Table 1. Objectives of Nodal Modeling for the NTP Study

| **Verify the feasibility of future scenarios by incorporating constraints that match physical realities of operating power systems** |
|---|
| - The physical network model captures power flow distributions and loading patterns across network elements (individual transmission lines and transformers).<br>- Physical infrastructure limits are captured (individual equipment ratings).<br>- Generators have distinct points of interconnection (POIs) and therefore drive related transmission network upgrades.<br>- The constraining of transmission flows aims to represent physical transmission margins that emulate actual operations.<br>- Enable more seamless data flow and obtain information to feed forward and feed back to other modeling domains. |
| **Gain grid-balancing insights based on detailed spatial and temporal modeling** |
| - Establish whether the system can balance load and generation at an hourly temporal resolution considering both intraregional and interregional transmission network constraints.<br>- Identify which resources are serving load during stressful periods and the role played by the transmission network to enable this.<br>- Analyze the use of expanded interregional transmission and how this impacts system operations.<br>- Analyze potential intraregional network constraints and the resulting need for upgrades and/or new investments.<br>- Test the latent and potentially increased need for flexibility in parts of CONUS-wide models (including the role of transmission in providing flexibility).<br>- Assess the operation of energy storage to support load and generation balancing, including the trade-offs with transmission network constraints.<br>- Understand how much and where variable renewable energy (VRE) curtailment is happening. |

# 2 Methodology

The following sections outline the methodology and workflows for the Z2N translation and the additional analysis that is performed with the nodal models. This is illustrated as a conceptual outline in Figure 1. The zonal input is a ReEDS scenario, which has 134 zones across the CONUS model.[3] The final nodal-level result is 1) a model year 2035 transmission portfolio that delivers broad-scale benefits and adheres to network constraints and 2) a production cost model that can be used to understand the operations at hourly resolution over a year (8,760 hours). Building the transmission portfolios and the nodal production cost model involves two primary steps:

1. **Disaggregation:** The assets that ReEDS builds (generation and storage) are disaggregated spatially across the United States within the zones and using other underlying information on asset location,[4] and assets are assigned points of interconnection (POIs) that already exist on the network.

2. **Transmission expansion planning:** New transmission is built within the nodal network models to connect the generation and storage assets, and additional transmission is built to connect regions and zones. The transmission for connecting regions and zones uses ReEDS results as an indication of need, but the exact transmission capacities from ReEDS are only guides and not prescriptive.

This transmission planning phase uses a combination of automated methods and an interactive transmission expansion planning approach to make decisions about discrete transmission expansions. The resulting transmission portfolios and production cost results are presented in this chapter and are used in Chapters 4 and 5 of this report for subsequent analysis. The following section describes the Z2N translation process.

[3] See Chapter 2 for more details on ReEDS and the zonal results.
[4] Wind and solar are built within the ReEDS scenarios based on supply curves with discrete 11.5-km x 11.5-km grid cells (for both wind and solar) across the United States. Therefore, these assets are at a finer resolution than the 134 zones and are interconnected spatially in the network models according to those grid points. See Chapter 2 for a more detailed explanation of ReEDS outputs.

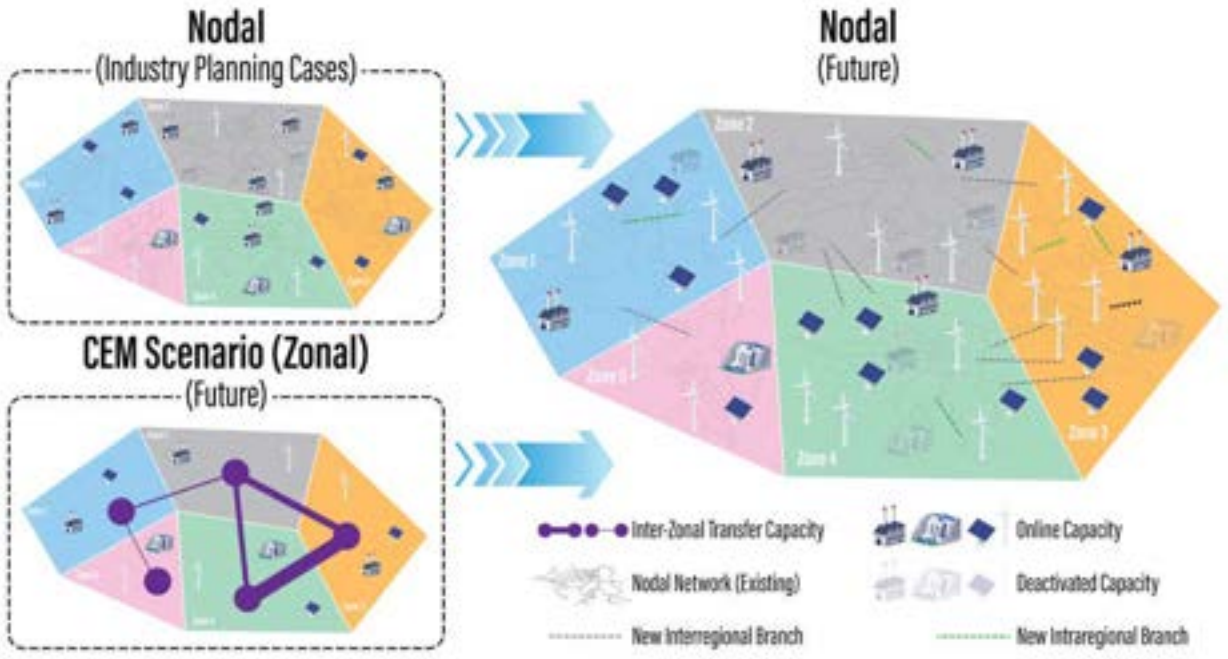



Figure 1. Conceptual outline of zonal-to-nodal translation

*CEM = Capacity Expansion Model*

### A note on using multiple software tools and workflows

Several of the results in this chapter originate from the earlier ReEDS scenarios, which represent a version that was completed midway through the NTP Study. These results are presented in Section 4. One of the primary purposes for using these interim results is the downstream models, especially the alternating current (AC) power flow models, can be very challenging and time-consuming to build and using the earlier scenario results allowed for a full run-through of the multimodel linkages—capacity expansion, production cost, and AC power flow—to be completed within the timeline of the study. There are slight differences between earlier and final scenarios (the scenarios analyzed in Chapter 2 are "final"), but both have the same general trends with respect to generation and transmission capacity buildout to the model year for this chapter: 2035. More details on the advancements made between earlier scenarios and final ReEDS scenarios are summarized in Chapter 1, Appendix A of this report.

The industry planning cases that are a starting point for the nodal analysis are the same between earlier and final scenarios. In building the future year nodal database, which requires the disaggregation and transmission planning steps outlined next, the same general principles for the Z2N process are used. However, though comparisons across modeling software of the same type (i.e., production cost) are not done in this chapter or anywhere else in the study,[1] there are still lessons from analyzing each set of scenarios that can strengthen the lessons from the study, which is the reason for including two sections of results. In addition, there is value to industry in having multiple production cost databases and transmission portfolios available as an outcome of the NTP Study, of which these will both be made available to industry and others where possible. Table 2 gives a summary of how earlier and final scenarios are used in this and other chapters.

Table 2. Different Use Cases for the Two Iterations of Scenarios Presented in This Chapter

| Iteration of Zonal ReEDS Scenarios | Section for This Chapter | Geographical Coverage Represented in the Models | Other Chapters That Directly Use These Capacity Expansion Iterations |
|---|---|---|---|
| Earlier | Section 4 | WI[1] | Chapter 4; Chapter 5 |
| Final | Section 3 | CONUS | Chapter 2 |

*WI = Western Interconnection; EI = Eastern Interconnection; CONUS = Contiguous United States*

## 2.1 Zonal-to-Nodal Translation

The Z2N translation is focused on transmission expansions and production cost modeling. The Z2N translation is a common process in industry, where resource plans are often developed at a zonal scale, but those plans eventually must be mapped to a nodal network model for a detailed transmission planning exercise.[5] There are many challenges to this process because zonal models, where policies or other techno-economic realities can be represented in detail, do not have the level of detailed network and physics-based constraints that exist in nodal models.

For the NTP Study, the challenges in this process are magnified because 1) the nodal datasets for the CONUS model(s) are very large, 2) the change with respect to the initial grid configuration is substantial, and 3) there is significant diversity in resources and network configurations across the United States, so strategies for the Z2N translation must be flexible.

The compiling and building of the nodal models follow a few basic principles:

- **Reproducibility between scenarios:** There are many potential methods to undertake the Z2N translation, as indicated by the multiple methods explained later in this chapter. However, the methods are reproducible across scenarios. Therefore, any comparisons of results in this chapter are across scenarios developed using the same methods.
- **Representing industry practice:** Z2N should build from industry best data and best practices. This starts with using industry planning models and learning from industry practices in their latest planning studies and in consultation with technical review committee (TRC) members. Section 2.1.1 details the starting datasets.
- **Using capacity expansion findings as a guideline:** Although generation capacity, storage, and demand are directly translated from the scenario-specific ReEDS outcomes, the prescribed interregional transfer capacities are used as a guideline for transmission expansion needs when building the nodal models.

An overview of the primary steps that form the entire Z2N translation is illustrated in Figure 2, starting with the results from ReEDS (1); moving into the disaggregation of zonally specified generation capacity, storage capacity, and demand into nodes (2); followed by a set of transmission expansion steps (3). The underlying nodal datasets that support this approach are further described in the next section.

[5] For example, California Public Utilities Commission. 2022. "Methodology for Resource-to-Busbar Mapping & Assumptions for The Annual TPP." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integratedresource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024- tpp-portfolios-and-modeling-assumptions/mapping_methodology_v10_05_23_ruling.pdf

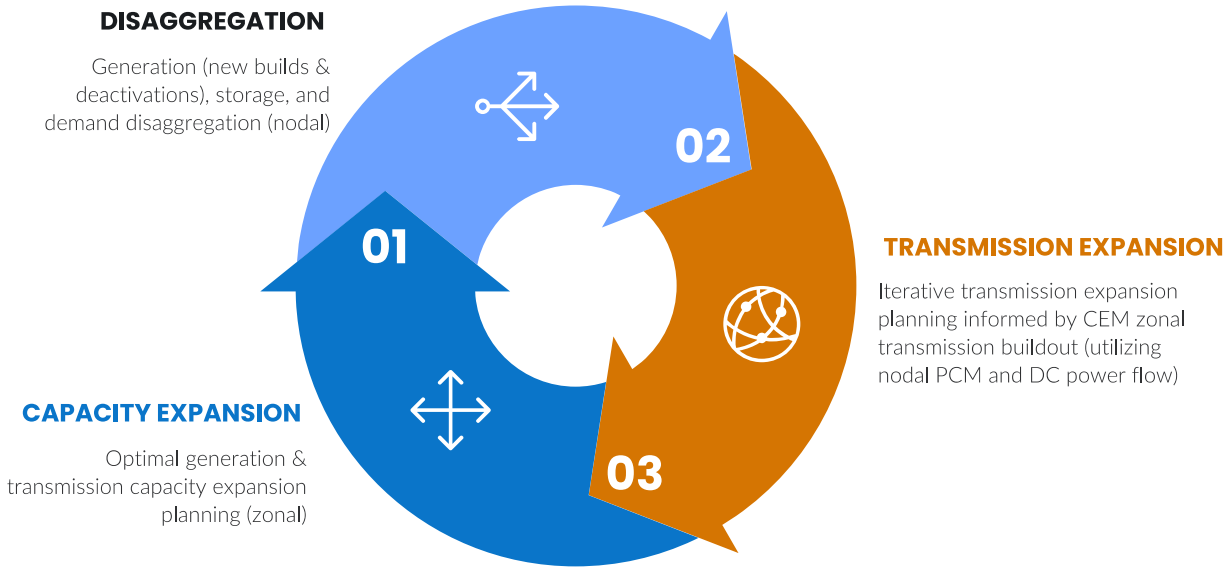



Figure 2. Overview of zonal-to-nodal translation approach

*Note: Figure incorporates iteration back to capacity expansion (ReEDS).*
*CEM = Capacity Expansion Model (ReEDS); PCM = Production Cost Model*

### 2.1.1 Geographic extent and nodal datasets

The CONUS bulk power system model used for the NTP Study comprises three regions—the Eastern Interconnection, Western Interconnection, and the Electric Reliability Council of Texas (ERCOT), shown in Figure 3. These interconnections are asynchronously interconnected through several relatively small back-to-back (B2B) HVDC converters.[6] The geospatial scope of the NTP Study is the contiguous United States. However, portions of Canada and Mexico are modeled but remain unchanged with respect to resources and transmission infrastructure in the study.[7]

[6] There are seven B2Bs between the contiguous U.S. portions of the Eastern and Western Interconnection (each ranging from 110 to 200 megawatts [MW]) and two between the Eastern Interconnection and ERCOT (200 MW and 600 MW). Not shown in Figure 3 are two B2B converters between Texas and Mexico (100 MW and 300 MW) as well as one between Alberta and Saskatchewan in Canada (150 MW).

[7] Industry planning models that are used for this study (see Table 3) include portions of Canada and Mexico. The regions are still part of the production cost and power flow models used in this chapter, but regions outside of the United States were not modified from the industry planning cases (i.e., load, generation, or transmission was not added).

Figure 3. Map of the three interconnections of the bulk U.S. power system

*Note: Map highlights the interconnectivity between interconnections via existing B2B HVDC interties.*

The nodal datasets used for the NTP Study are compiled from the industry planning cases from the Western Electricity Reliability Council (WECC),[8] Eastern Interconnection Reliability Assessment Group (ERAG),[9] and to some extent ERCOT[10]—the details of which are summarized in Table 3. These datasets typically do not have all relevant details to inform a Z2N translation, i.e., geographical coordinates required to map zonal capacity expansion results to individual nodes or run future scenarios beyond the planning case timeline. Though WECC publishes a fully functional production cost model as part of its Anchor Dataset (ADS), the ERAG and ERCOT available data lack component information to build and run production cost models, such as generator unit constraints (ramp rates, minimum stable levels, and minimum uptime and downtime, among others), detailed hydro availability, or hourly wind and solar profiles. A task within the NTP Study was designed to fortify the industry planning cases for the Eastern Interconnection and ERCOT to be suitable for this study. The WECC ADS model details were used directly for the CONUS scenarios. For the Western Interconnection analysis

[8] Through the well-known WECC Anchor Dataset (ADS) (Western Electricity Coordinating Council 2022).
[9] The Eastern Interconnection Reliability Assessment Group (ERAG) oversees the Multiregional Modeling Working Group (MMWG), which is responsible for assembling nodal network models for the Eastern Interconnection (among other responsibilities).
[10] WECC is the regional entity responsible for reliability planning and assessments for the Western Interconnection and has nodal models of the Western Interconnection available for members. EIPC is a coalition of regional planning authorities in the Eastern Interconnection that compiles a power flow model of the Eastern Interconnection based on regional plans. ERCOT did not provide an updated power flow model from this study; therefore, data were compiled from publicly available sources and purchased data.

of the earlier scenarios, an augmented model was developed to include five future transmission projects. For details on the development of the Western Interconnection database, see Konstantinos Oikonomou et al. (2024).

The nodal datasets of the Eastern Interconnection, Western Interconnection, and ERCOT are each developed independently and then combined to form the CONUS nodal dataset. A summary of sources for the data in the nodal models is presented in Table 3, with a more comprehensive table in Appendix A.1. Some of the benefits realized and challenges faced in compiling a CONUS-scale dataset are summarized in Appendix A.2.

Table 3. Overview of Data Sources Used for Building CONUS Datasets

| Description | Eastern Interconnection | Western Interconnection | ERCOT |
|---|---|---|---|
| Network topology (node/branch connectivity)[1] | ERAG MMWG 2031[2] | WECC ADS 2030 v1.5 | EnergyVisuals[5] |
| Node mapping (spatial) | NARIS, MapSearch, EnergyVisuals, EIA 860 | NARIS MapSearch, EnergyVisuals, EIA 860 | NARIS, MapSearch, EnergyVisuals |
| Generation capacity (technology) | NARIS, EIA 860, EIPC | WECC ADS 2030 v1.5, EIA 860 | NARIS |
| Generation techno-economic characteristics[3] | NARIS, EIA CEMS | WECC ADS 2030 | NARIS |

*[1] Augmented through stakeholder feedback to include the most recent available data on network updates/additions.*

*[2] Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2021 series (2031 summer case).*

*[3] Includes heat rates, minimum up-/downtimes, ramp rates, and minimum stable operating levels.*

*[4] Hourly/daily/monthly energy budgets (as appropriate).*

*[5] Power flow case files (2021 planning cases).*

*ADS = Anchor dataset (Western Electricity Coordinating Council 2022); CEMS = continuous emission monitoring system; EER = Evolved Energy Research, MMWG = Multiregional Modeling Working Group; NARIS = North American Renewable Integration Study (National Renewable Energy Laboratory [NREL] 2021a); WECC = Western Electricity Coordinating Council*

### 2.1.2 Modeling domains and tools

Several modeling domains are applied as part of the iterative Z2N translation process. For disaggregation, many custom tools were built to map zonal resources and network assets. A summary of the primary modeling tools for the transmission expansion phase is shown in Table 4.

Table 4. Primary Models Used in the Transmission Expansion Phase of the Z2N Translation

| Step in Transmission Planning Phase of Translation | Primary Modeling Tools |
|---|---|
| 1. Production cost | Sienna,[11] GridView[12] |
| 2. Power flow and contingency | PSS/E,[13] PowerWorld Simulator[14] |
| 3. Visualization | QGIS,[15] Grid Analysis and Visualization Interface[16] |

The outputs of the ReEDS scenarios are used as inputs into the disaggregation step. The objective of disaggregation is to translate new electricity demand, generation, and storage that is built in the scenario from ReEDS to augment an established industry planning case to build scenario-specific nodal production cost models. Section 2.2 details this process.

However, not all resources are easily placed on the network with automated processes, and additional expertise is needed to make decisions about resource allocation to nodes. Interventions are needed for some specific instances, where the resource—for example, wind—might be in such high quantities that a substation or entire high-voltage/extra high-voltage (HV/EHV) collector network[17] might need to be considered. These interventions are where the transmission expansion planning phase begins. The software and tools in Table 4 are used to both ensure generation and storage have sufficient transmission to interconnect to the network and transmission portfolios are designed to meet the needs of the system and reflect the intention of the ReEDS scenario. Several times throughout the design of the transmission portfolios, production cost models and DC power flow models are run and analyzed to assess how the system operates—that is, energy adequacy, hourly balancing of supply and demand, variable renewable energy (VRE) curtailment, individual branch loading, and interface flows. Section 2.3 details this phase of the Z2N process.

The nodal production cost models are the core analytical tools used in the Z2N process—employed extensively in the transmission expansion planning phase and producing the operational results analyzed for Sections 3 and 4. They also seed the operating points for the more detailed reliability analysis described in Chapter 4 and Chapter 5. The open-source modeling framework, Sienna/Ops, is used as the

[11] Sienna: https://www.nrel.gov/analysis/sienna.html, last accessed: February 2024.
[12] GridView: https://www.hitachienergy.com/products-and-solutions/energy-portfolio-management/enterprise/gridview, last accessed: May 2024.
[13] Siemens PSS/E, https://www.siemens.com/global/en/products/energy/grid-software/planning/pss-software/pss-e.html, last accessed: February 2024.
[14] PowerWorld Simulator, https://www.powerworld.com/, last accessed: March 2024.
[15] QGIS, https://www.qgis.org/en/site, last accessed: May 2024.
[16] For the final scenarios, the study authors developed the Grid Analysis and Visualization Interface to help visualize the system operations and support transmission planning. Details are presented in Appendix C.2.
[17] As defined in ANSI C84.1-2020 where HV = 115–230 kilovolts (kV) and EHV = 345–765 kV.

production cost model for transmission planning and operational analysis for final scenarios (Section 3 of this chapter) whereas GridView[18] is used for earlier scenarios (Section 4 of this chapter).

## 2.2 Disaggregation

The Z2N disaggregation relies on two principles about how to convert ReEDS results to nodal models: 1) generation and storage planned in ReEDS must align with the nodal model very closely (i.e., prescriptive) and 2) transmission results from ReEDS are indicative of the needed transmission capacity to move energy between regions. Demand is also prescriptive because it is an input to the zonal model. The distinction between the prescriptive and indicative use of zonal results is summarized in Figure 4.

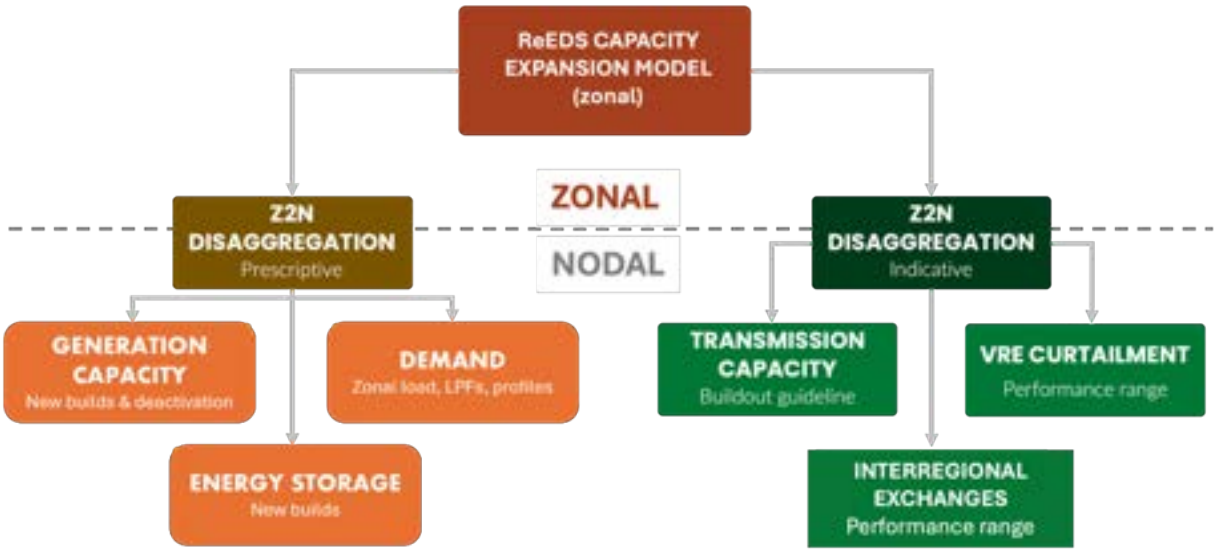



Figure 4. Overview of the zonal results flowing into the nodal model

*LPF = load participation factor*

The prescriptive component of the Z2N process comprises four primary steps:

1. **Demand disaggregation:** Demand disaggregation is needed to represent load profile time series in nodal production cost models because only zonal demand is provided by ReEDS outcomes. ReEDS zonal demand is disaggregated into nodes for each ReEDS region based on load participation factors (LPFs)[19] derived from the industry planning power flow models. This process is depicted geospatially in in Figure A-38 in Appendix A.3, demonstrating how a single zonal

[18] GridView: https://www.hitachienergy.com/products-and-solutions/energy-portfolio-management/enterprise/gridview, last accessed: May 2024.
[19] Load participation factors (LPFs) are a measure to assess the contribution of an individual load to overall load in a region. In the context of the NTP Study, LPFs are derived from absolute nodal loads in the nodal datasets to generate load profiles from ReEDS zonal loads for nodal production cost model analysis.

demand profile from a ReEDS zone is disaggregated into the many nodes based on the relative size of each load (their LPFs).

2. **Establish the generation and storage capacity needs for each zone in the nodal model year:** To establish the amount of generation and storage to add to the system, the study team compared industry planning cases with the ReEDS scenario. Generation and storage capacity is added or subtracted (i.e., deactivated) to the nodal models to reach prescribed capacities defined by ReEDS.[20]

3. **Ranking of nodes—POIs:** To assign zonal capacities to nodal models, the study team ranked nodes by generation and storage capacity POI favorability. Viable nodes[21] are ranked by build favorability. Higher build favorability considers the following (in descending order): 1) nodes with more deactivated/retired capacity, 2) nodes at higher voltage levels, 3) nodes or surrounding nodes with large loads attached.[22]

4. **Adding generation and storage capacity:** The final step in the disaggregation is to link new generation and storage capacity defined in ReEDS to actual nodes, or POIs. Figure 5 illustrates the spatial clustering of solar photovoltaics (PV) and land-based wind to POIs. After initial clustering to POIs, further refinement may be required to ensure node capacities are reasonable given network constraints. Appendix A.3 contains further details on this step.

[20] ReEDS compiles any known generator retirements from EIA or other sources and exogenously enforces them. In addition, ReEDS can retire generation economically. See Chapter 2 for more details.
[21] Nonviable nodes may be terminals of series capacitors, tap-points, fictitious nodes to indicate conductor changes (or three-winding transformer equivalents) and disconnected/isolated busses.
[22] For allocating distributed energy resources (distributed solar PV), which is consistent across all NTP scenarios (sensitivities on types of distributed energy resources, quantity or distribution of distributed energy resources is out scope for the NTP Study).

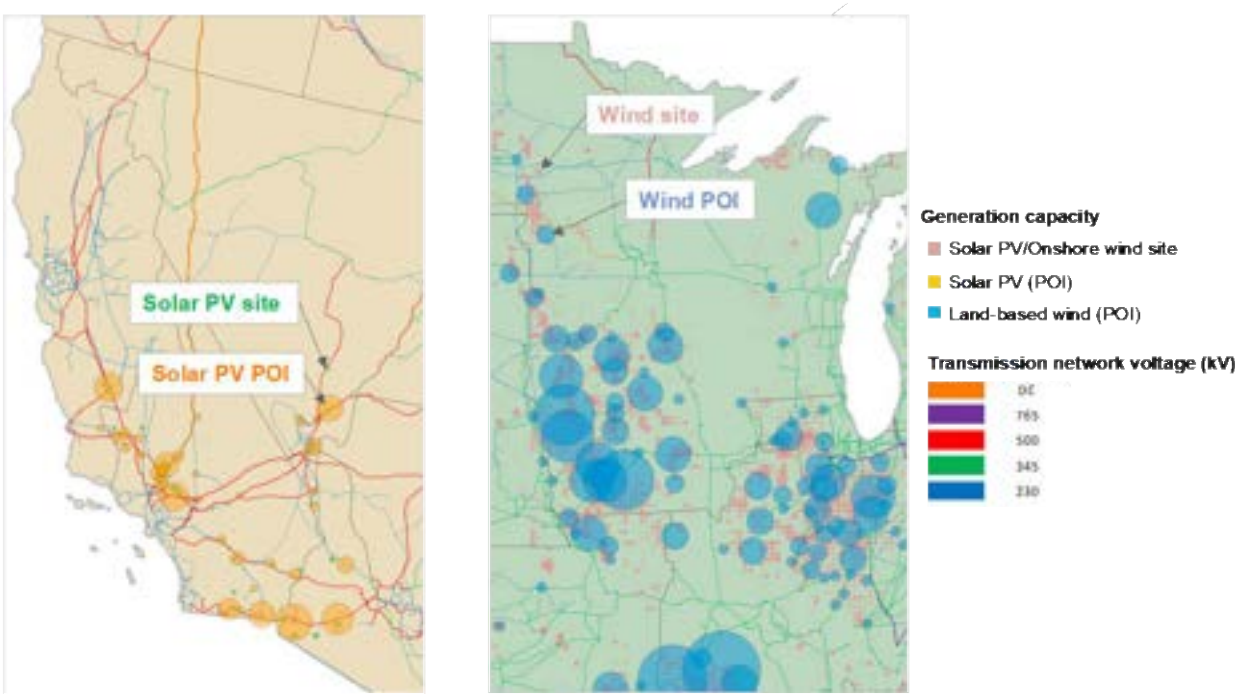



Figure 5. Illustration of VRE disaggregation process as part of Z2N translation

*Note: The VRE disaggregation is demonstrated for solar PV (left) and land-based wind (right) where individual solar PV and wind sites are assigned to POIs (nodes).*

## 2.3 Transmission Expansion

Nodal transmission expansion comprises a key part of the overall Z2N translation workflow. The scenarios for the NTP Study are transformational, in part because of the decarbonization targets enforced in several of them and the scale of transmission allowed. Therefore, the study team developed a transmission expansion process that could meet the demands of potentially large buildouts in interregional and regional networks. In addition, this process needed to be manageable at an entire interconnection and contiguous U.S. scale. This manageability is achieved through stages of increasing complexity to maintain tractability as the transmission portfolios are built out in the nodal production cost model. This staged process is summarized in Figure 6. Each stage becomes progressively more constrained and can have several internal iterations per stage.

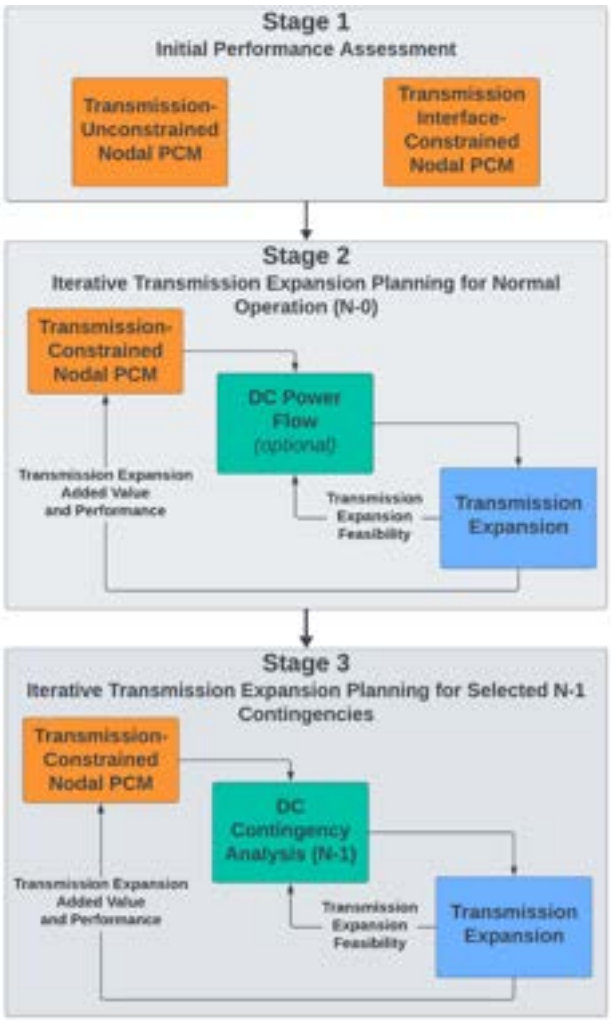



Figure 6. Stages of transmission expansion planning

*Orange boxes indicate a nodal production cost model, teal boxes indicate DC power flow, and blue boxes indicate transmission expansion decisions by a transmission planner.*

The transmission expansion planning process applies the staged principles to remain consistent across CONUS and is not intended to exactly replicate transmission planning processes or adopt regionally specific technical transmission guidelines/standards as applied by regional transmission planners, owners/developers, or utilities. In addition, to help visualize the large changes and impacts to the Z2N scenarios, the Grid Analysis and Visualization Interface tool was created to visualize hourly production cost model results (see Appendix C.1 for an overview of this tool).

The sections that follow provide further details of the staged transmission expansion process depicted in Figure 6.

**Stage 1: Initial network performance assessment**

Stage 1 is a performance assessment intended to provide an initial analysis of system operations and transmission network use before transmission expansion is undertaken.

The initial disaggregation of resources has already been implemented when this first stage of transmission expansion planning is reached (see Section 2.2). Therefore, the Stage 1 nodal production cost model runs contain all the generation and storage resources built in the ReEDS scenario.

Stage 1 is implemented by a nodal PCM with two core transmission network formulations:[23]

- **Transmission unconstrained:** No transmission interface or branch bounds are applied (analogous to a "copper sheet" formulation but with network impedances represented to establish appropriate flow patterns)
- **Transmission interface constrained:** Only transmission interface limits are enforced (individual tie-line branch limits are unconstrained).[24]

The unconstrained nodal production cost model establishes where power would want to flow without any network constraints and hence establishes an idealized nodal realization without network bounds. The semibounded interface-constrained nodal production cost model establishes an indicator for interregional and enabling intraregional transmission network needs by allowing individual branch overloading but ensuring interregional tie-line flows remain within the limits established from the ReEDS transfer capacities (aggregated to transmission planning regions).[25]

At this stage, the following system performance indicators are assessed (for both transmission-unconstrained and transmission interface-constrained formulations):

- Interregional power flow patterns across sets of transmission interfaces (tie-lines)
- Individual tie-line power flow patterns and loading profiles
- Individual HV and EHV transmission line loading profiles
- Regional wind and solar PV curtailment levels
- Operations of dispatchable resources.

After establishing general flow patterns within and between regions in Stage 1, the study team proceeded with Stage 2.

[23] Further details on transmission formulations are provided in Appendix A.4.
[24] Transmission interfaces are defined as the sum power flows across each individual tie-line part of the given interface.
[25] Using constrained and unconstrained production cost models as a way to gather information about the system potential is typical in industry planning, for example, in Midcontinent Independent System Operator (MISO) (Dale Osborn 2016).

### Stage 2: Iterative transmission expansion planning for normal operations (system intact)

Stage 2 expands the HV and EHV transmission networks for normal operating conditions (system intact). To plan the transmission expansion, an iterative approach is deployed, which includes the following steps:

1. **Performance assessment:** From a set of nodal production cost model results (Stage 1 transmission interface-constrained or a Stage 2 iteration), assess network use metrics such as interface flow duration curves, loading duration curves of individual tie-lines, individual HV and EHV transmission line loading profiles, VRE curtailment, dispatch of resources (generation, storage), and unserved energy.
2. **Transmission expansion planning:** Based on the interface flow patterns, iteratively propose and test nodal transmission expansion options to increase transmission capacities while managing HV and EHV network overloads. The quick assessment of the feasibility of the proposed transmission expansion options can be obtained by employing DC power flow[26] simulations as an intermediate step prior to running a new nodal production cost model simulation including the additional transmission network elements.
3. **Nodal production cost model:** Once a substantial set of new transmission expansions meets performance metrics in the DC power flow simulations, the nodal production cost model is adapted with the new transmission and run with an increasing set of network constraints.

In each iteration of the Stage 2 transmission expansion process described previously, different transmission expansion priorities are addressed. Figure 7 shows the priority order followed for the definition of the network expansion options defined in Stage 2.

Once the Stage 2 transmission expansion planning process is complete, the system operation performance is assessed using a constrained nodal production cost model formulation incorporating all the proposed transmission expansion portfolios. Given good performance in the nodal production cost model, this establishes the starting point for Stage 3. Criteria considered in evaluating production cost model performance are unserved energy, new transmission utilization, and VRE curtailment.

[26] DC power flow simulations are performed over a subset of the 8,760 operating conditions from the nodal production cost model results. These representative operating conditions are called “snapshots.” The selection of these snapshots is made to capture periods of high network use from different perspectives, such as peak load conditions, high power flows across interfaces, and between nonadjacent regions. See Appendix A.6 for an outline of periods selected as snapshots.

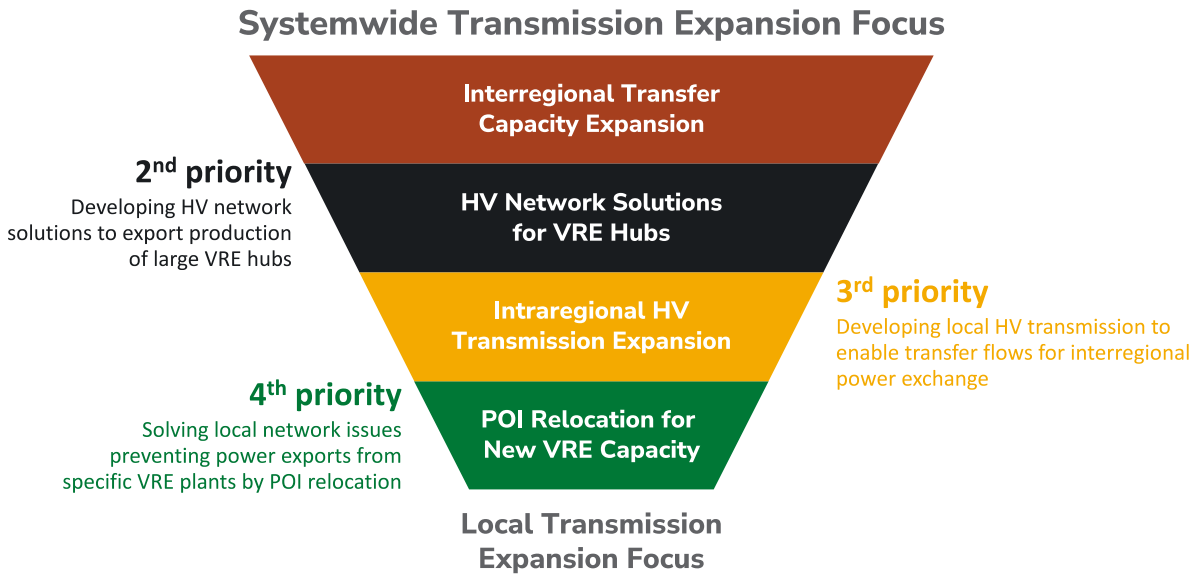



Figure 7. Prioritization of transmission expansion planning approach

### Stage 3: Transmission expansion planning with selected single transmission network contingencies

Stage 3 of the Z2N process applies similar logic to that of Stage 2 but with the system intact linear power flow analysis being replaced by selected single contingency linear-power-flow-based contingency analysis. Contingencies are defined as individual branch element outages,[27] which include the subset of branches that form tie-lines between transmission planning regions[28] plus all lines within a transmission planning region that directly connect to a tie-line ("first-degree neighbors") inclusive of any newly added tie-lines between regions (as shown in Figure 8).

The planning criteria applied in the final scenarios' CONUS expansion results are the monitoring of all branches greater than or equal to 220 kV, postcontingency overload threshold of 100% of emergency ratings ("Rate B") for lines not overloaded in the precontingency state, and postcontingency loading change greater than 30% (relative to the precontingency state) for lines already overloaded in the precontingency state.[29] In the earlier scenario results for the Western Interconnection (results shown in Section 4), the emergency rating is used for postcontingency flows. When this is not available,

[27] Analogous to P1 and P2 type contingencies defined in NERC TPL-001-5 (North American Electric Reliability Corporation [NERC] 2020).
[28] The regional boundaries between transmission planning regions and the underlying balancing authorities (BAs) in industry are slightly different from those used in the NTP Study. Chapter 2 maps the assumptions for the geographic bounds of the regions used throughout the NTP Study.
[29] In cases where a transmission line under the contingency list is modeled as a multisegment line or includes a tap point without any load or generator connected to it, the selected single contingency is modeled to include the tripping of all segments composing the model of the given single contingency. In other words, a single contingency is modeled by tripping multiple elements simultaneously. In cases where Rate B = Rate A or Rate B = 0 in datasets, the postcontingency threshold is set to a default of 120% of Rate A (135% for earlier scenario analyses).

135% of normal rating is used. Because all branch constraints for branches 230 kV and above are enforced, no additional threshold is provided for precontingency overloaded branches. Decisions on expanding the network following the linear (DC) contingency analysis are based on consistent and/or widespread network overloads.

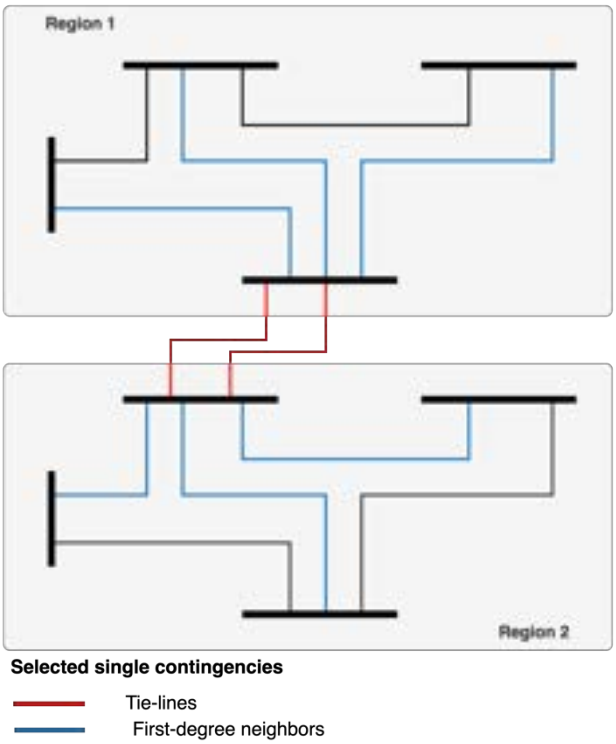



Figure 8. Illustration of single contingency definition for Stage 3 of zonal-to-nodal process

*The selected single contingencies that comprise the contingency analysis are composed of tie-lines (red) and first-degree neighbors (blue).*

Additional network expansions following the DC contingency analysis results are based on the principles depicted in Figure 9. In situations where a given contingency causes consistent and widespread network overloads, transmission reinforcements around the given contingency are proposed (mitigation of the cause). In situations where a given network element(s) is consistently overloaded across multiple contingencies and/or multiple operating conditions, network reinforcement solutions around the impacted element(s) are proposed (mitigation of the consequences).

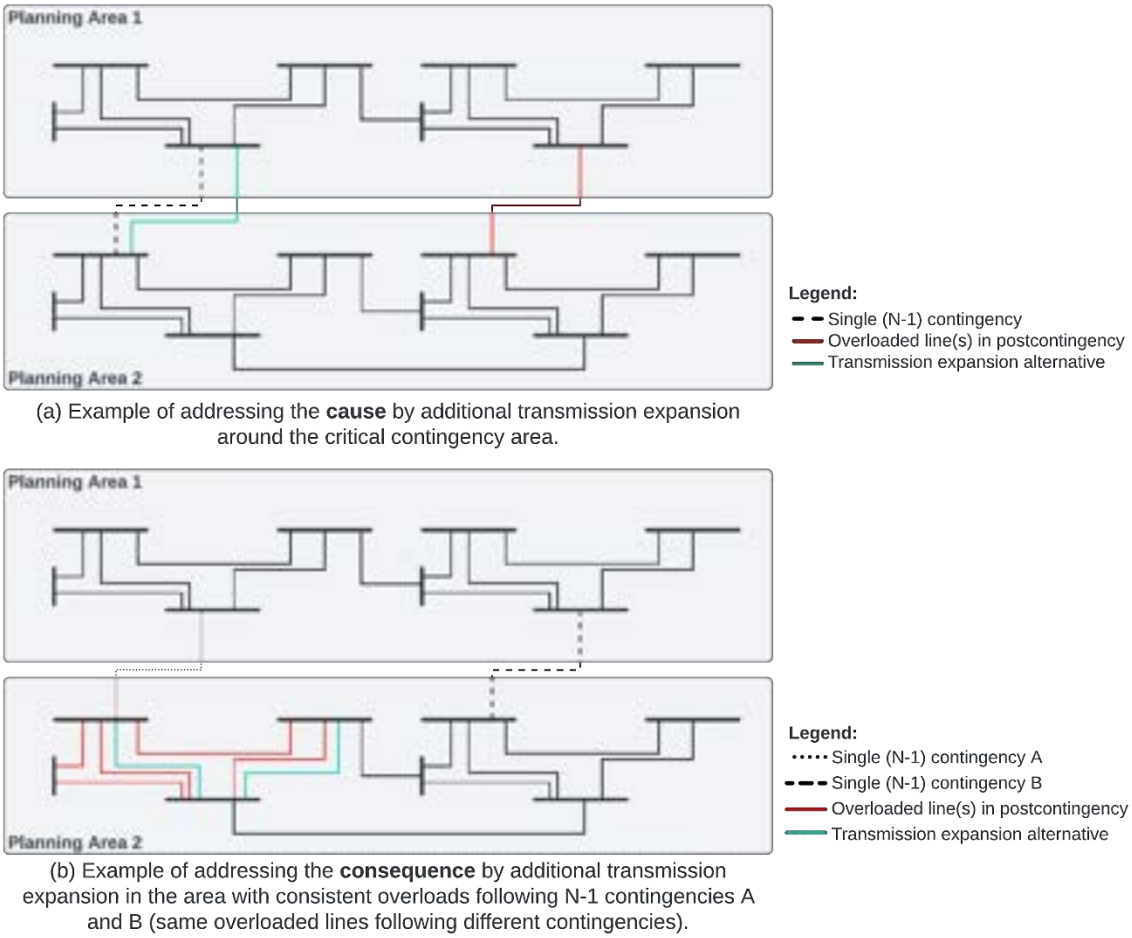



Figure 9. Illustration of mitigation of causes and consequences during contingency analysis

The study team performed contingency analysis on all existing and new interregional tie-lines as illustrated in Figure 8 and Figure 9. The contingency analysis is intended as a screen to address large interregional contingency risk considering some ties (500 kV and 765 kV in particular) have the potential to carry large amounts of power—on the order of 3000–5000 MW. However, the contingency analysis is not a comprehensive intraregional contingency assessment, so further analysis of new transmission expansions would be necessary when moving toward detailed network design stages, which is beyond the scope of the NTP Study.[30]

## 2.4 Transmission Planning Feedback to Capacity Expansion

The NTP Study approach included a feedback loop between zonal ReEDS capacity expansion findings and downstream nodal models to capture key learnings from initial capacity expansion findings and resulting downstream nodal model findings, illustrated in Figure 10. During the initial modeling for the NTP Study, the team had several rounds

[30] The results for Section 4 use a variation of the contingency method illustrated here. See Appendix A.7 for an explanation of this method, which was applied to the Western Interconnection earlier scenarios.

of scenarios that were used to refine these multimodel linkages and feedback constraints to ReEDS based on the buildout of nodal models. This feedback mainly focused on the following:

1. Improving the spatial distribution of wind and solar resources
2. Constraining maximum interzonal transmission buildout capacities.

For Item 1, the study team recognized that regions with large interregional transmission would in some cases require substantial intraregional network strengthening to accommodate large transfers to other regions. The result of the feedback is an improved representation of spur and reinforcement costs in the ReEDS final NTP Study scenarios, which is described further in Chapter 2. As an indirect effect of this improvement, concentrating large amounts of generation and transmission infrastructure in small geographical footprints is lessened.

For Item 2, the feasibility of certain high-capacity corridors in the earlier rounds of zonal capacity expansion modeling results was flagged by TRC members and the study team as being difficult to implement. In developing transmission portfolios of these corridors in the Z2N translations, several technical challenges were revealed with respect to the amount of transmission capacity that could be practically realized between ReEDS regions (both spatially and electrically). As a result, an upper bound of 30 gigawatts (GW) of maximum transmission buildout across a given corridor was set for the final round of ReEDS scenarios.

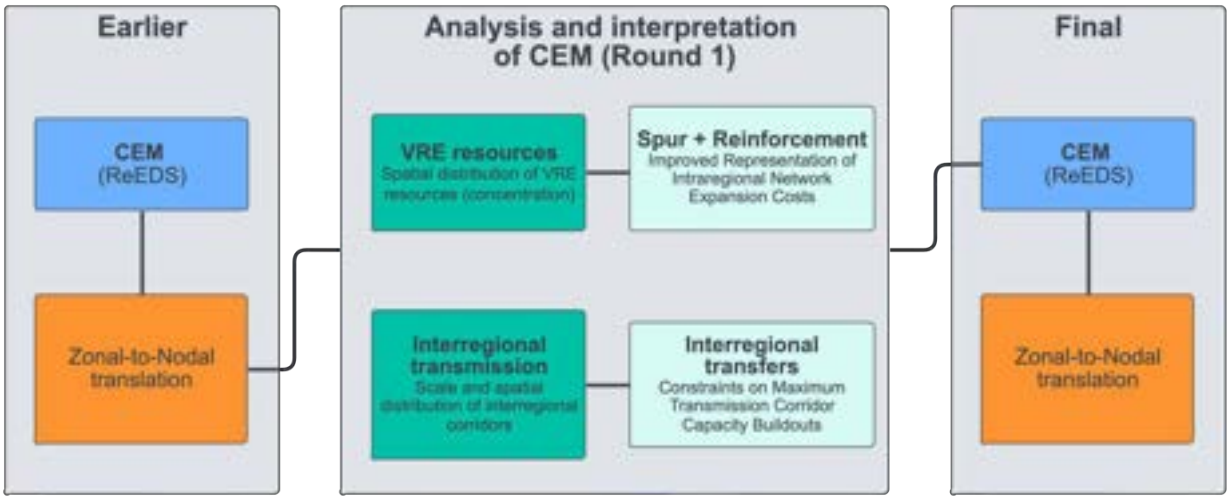



Figure 10. Overview of transmission expansion feedback between zonal and nodal modeling domains

## 2.5 Scenarios for Nodal Transmission Plans and Production Cost Modeling

A subset of the 96 scenarios from ReEDS was chosen to be translated into nodal scenarios because of the complexity of working with large nodal power system models. Therefore, the study team narrowed down the scenarios with the intent to understand distinct transmission expansion learnings between each scenario, interest from the TRC, and feasibility of implementation. The study team opted for scenarios situated between the extremes of cost and demand projections as well as technology advancements. In addition, though the scenarios from ReEDS extend to 2050, the nodal models for this chapter are focused on 2035 to understand the more immediate implementation challenges. Table 5 summarizes the three scenarios for the development of nodal interregional transmission expansion.

Table 5. Summary of Scenarios for Zonal-to-Nodal Translation

| Dimension | Limited | AC | MT-HVDC |
|---|---|---|---|
| Transmission framework[1] | AC expansion within transmission planning regions | AC expansion within interconnects | HVDC expansion across interconnects (+AC within transmission planning regions) |
| Model year | 2035 | | |
| Annual electricity demand | Mid Demand[1]<br>CONUS: 5620 TWh (916 GW)<br>Western Interconnection: 1097 TWh (186 GW)<br>ERCOT: 509 TWh (93 GW)<br>Eastern Interconnection: 4014 TWh (665 GW] | | |
| $CO_2$ emissions target | CONUS: 90% reduction by 2035 (relative to 2005) | | |

[1] *See Chapter 2 for further details.*

*CO2 = carbon dioxide; AC = alternating current; TWh = terawatt-hour; GW = gigawatt; HVDC = high-voltage direct current*

A summary of the interregional transmission expansion from the ReEDS zonal scenarios is shown in Figure 11 (aggregated to the subtransmission planning region level).[31] Maps of the results of zonal transmission expansion from ReEDS for the three scenarios are shown in Appendix B.4. Large transmission planning regions are split into meaningful subregions for transmission expansion, analysis, and insights from zonal ReEDS findings.

[31] All results in this chapter from the zonal ReEDS capacity expansion are analyzed in greater detail in Chapter 2. Chapter 2 highlights more 2050 results, although Appendix B of Chapter 2 provides an overview of the 2035 results.

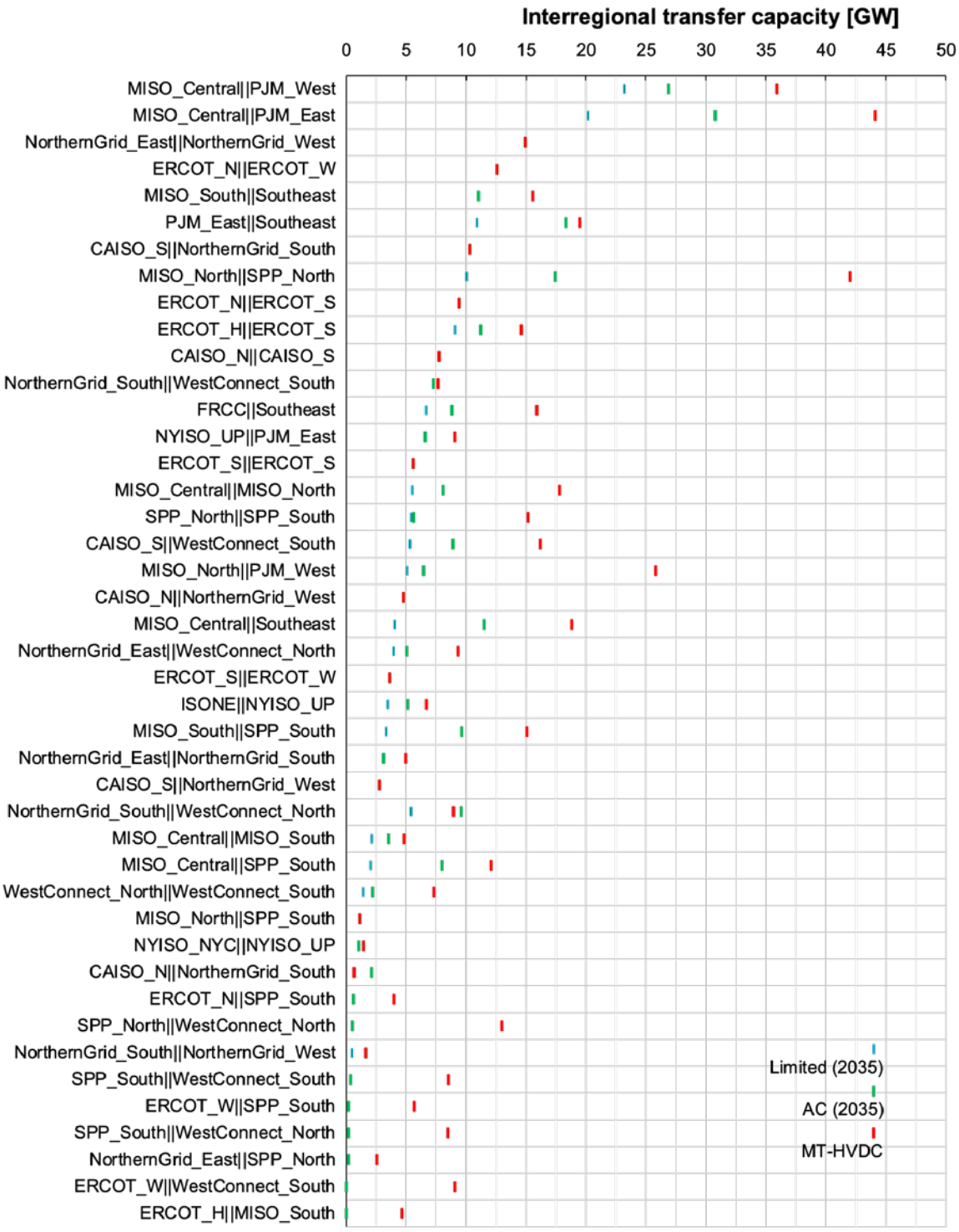



Figure 11. Interregional transfer capacity from ReEDS zonal scenarios used for nodal Z2N scenarios

## 2.6 Economic Analysis of the Western Interconnection (earlier scenario results)

This economic analysis evaluates the avoided costs and disaggregates economic benefits among different network stakeholders of the nodal scenarios from the earlier ReEDS expansions. The Limited scenario is used as a reference to estimate the avoided cost of the AC and MT-HVDC cases. This study uses avoided costs as the metric to estimate the economic benefits of transmission capital, generation capital, and operation. Avoided cost is an accurate measure of the economic benefits when load demand is constant across the scenarios analyzed (Hogan 2018; Mezősi and Szabó 2016). See Appendix D.4 for a brief discussion of prior studies that have estimated the economic benefits of transmission. The production cost modeling uses the same demand as an input to the scenarios modeled, so this condition is met for the scenarios in this study. The overall avoided costs are estimated as the sum of the capital and operational avoided costs after they have been annualized to enable comparison of avoided costs that occur over different time horizons. This section discusses the methodology of how the capital costs of generation and transmission were developed. The section also describes the methodology for estimating the total avoided costs using annualized values as well as the methodology used to disaggregate the avoided costs as benefits among different network users. Disaggregating the benefits can help understand how the avoided costs enabled by interregional transmission could economically benefit different stakeholders, providing information to the multiple groups that must collaborate to build transmission infrastructure.

### 2.6.1 Transmission capital cost methodology

Transmission costs are based on the transmission lines added to the GridView Production Cost Model by voltage class (230 kV, 345 kV, and 500 kV) according to the methodology introduced in the previous sections. The study team used the WECC Transmission Calculator (Pletka, Ryan et al. 2014) that was updated by E3 in 2019 (E3 2019) to calculate the capital costs for transmission. New generation is added to viable POIs at 230 kV and above. If no POI is sufficiently close,[32] a new POI is created. As such, a significant portion of what might be called “spur lines” in the capacity expansion model is explicitly modeled in the nodal builds. The WECC Calculator multipliers for land ownership and terrain were used to estimate the cost of added transmission along with the costs associated with the allowance for funds used during construction (AFUDC).[33] Appendix D.3 provides more detail on the land ownership and terrain multipliers.

### 2.6.2 Generation capital cost methodology

Generation capital costs are taken directly from ReEDS outputs from earlier scenarios for 2022–2034 for Limited, AC, and MT-HVDC. The capital cost inputs to ReEDS for each generation type are taken from the Annual Technology Baseline (ATB)

[32] For all wind and solar locations in the AC and Limited (Lim) scenarios, the average distance to their POIs is 17 miles.
[33] AFUDC is the cost of money invested or borrowed during construction that must be accounted for in the total costs of construction.

database (National Renewable Energy Laboratory 2023). The values are in 2004$ and were escalated to 2018$ using the Consumer Price Index to match year dollars in GridView. Costs are not split between the resource types, meaning all generation capital costs are aggregated to a single dollar number.

### 2.6.3 Operating cost economic metrics methodology

The total economic benefits are estimated as the avoided cost for grid operation, across the different transmission topologies. The costs modeled in GridView include fuel, startup, shutdown, and other variable operating costs. The relative avoided costs of the AC and MT-HVDC transmission topologies can be calculated by subtracting the total cost of the AC and MT-HVDC scenarios from the Limited scenario:

$$\text{Avoided Cost}_i = \text{Cost}_{Lim} - \text{Costs}_\text{i}\ i \in \{\text{AC, MT-HVDC}\}.$$

The study team estimated the subsidy payments for the investment tax credit (ITC) and production tax credit (PTC). The ITC applies a 30% credit to generation capital costs for solar plants[34] (U.S. Department of Energy [DOE] 2022a) and the PTC applies a $26/MWh credit to wind generation (DOE 2022b).

### 2.6.4 Net annualized avoided cost methodology

To account for the difference in timing and useful lifetime of the different capital investments, the study team annualized the avoided transmission capital costs and the avoided generation capital costs. The net annual avoided costs are equal to the sum of the annual avoided operation costs and the annualized avoided capital costs. When net annualized avoided costs are greater than zero, the scenario should be considered to have positive overall avoided costs. The following formula is used to compute the annualized cost:

$$Annualized\ Cost = C \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where *r* is the discount rate and *n* is the assumed lifetime of the infrastructure. The study team used discount rates of 3% and 5% to show the net annualized value across a range of discount rates. The assumed life of transmission capital is 40 years, and the assumed life of generation capital is 20 years. Annualized value is also sometimes called the annuity value and can be interpreted as the annual payment required over the lifetime of an investment to be equivalent to the net present value of an investment paid today as a lump sum (Becker 2022).

### 2.6.5 Benefit disaggregation and calculating the annualized net present value

In this chapter, the study team disaggregated system benefits according to different network users, such as the consumers, the producers, and transporters. For the grid, the generators are the producers, transmission owners are the transportation entity, and power purchasers are the consumers. The NTP Study does not model the final stage of

[34] These use round 1 ReEDS results where solar is assumed to take the ITC. This does differ from round 2 results where solar takes the PTC.

the grid where the power purchasers distribute load to the end consumers through the ratemaking process. This ratemaking process varies across states and utilities, but in general costs (and avoided costs) are passed on to consumers through this process.

Disaggregating benefits according to network users provides additional information that could enable more efficient planning to utilities, independent system operators (ISOs), and system operators. For a single decision maker, such as a vertically integrated utility, the optimal transmission topology would minimize system cost required to serve load demand subject to regulatory requirements. In contrast, in a pure market setting, the optimal transmission topology would be consistent with the market equilibrium where market participants (network users) take prices as given (Hogan 2018). The electric grid is a hybrid of these two structures. Many regions are served by a single utility; however, interregional transmission typically requires collaboration across multiple utilities, ISOs, and local stakeholder groups. In addition, wholesale electricity markets are becoming more prevalent, and the frequency of power purchase agreements (PPAs) between generators and utilities or consumers is increasing. Understanding the relative benefits to different network users can help achieve a broader consensus among network users that must cooperate to build interregional transmission (Kristiansen et al. 2018).

A critical component required to disaggregate economic benefits is an estimate of the market price. Electricity price forecasts typically use historical data on electricity prices and other variables. This can result in high forecast error as the forecast progresses farther into the future and as other conditions change (Nowotarski and Weron 2018). The most common approach for estimating prices from PCM simulations is to use the locational marginal prices estimated by the model. However, the simulated LMPs estimate revenues that are insufficient for cost recovery for most generators in the model. The scenarios simulated the 2035 grid with significantly higher renewable penetration than at present, making a forecast using the simulated locational marginal prices, or present and historical prices unreliable. To alleviate this issue, the study team assumed each generator receives its levelized cost of energy (LCOE) as its price, approximating the lower bound that the generators would need, on average, to attract investment financing. LCOE values were obtained from the ATB dataset for land-based wind, offshore wind, solar PV, geothermal, battery storage, and hydropower using moderate estimates, research and development (R&D) financials, and the year 2035. LCOE values were obtained from Lazard (2023) for nuclear, coal, and natural gas (Lazard 2023). This assumption models a generator operating under a PPA at a set price or a price that is steadily escalating with inflation over time. LCOE represents the minimum average price that a generator project requires to attract capital investment (Lai and McCulloch 2017). This assumption ensures the modeled price is sufficient for investment in the modeled generation capacity to occur. Of note, the disaggregation of benefits and the modeling assumptions for prices do not affect the total benefit estimates. Changes in prices will cause a transfer of benefits between generators and power purchasers but does not affect the total benefits.

Generator benefits are estimated using the profits (revenue minus cost) to the generators. The generator costs were obtained from the GridView simulations. Generator revenue is estimated by multiplying the price (LCOE) by the dispatched

generation—that is, generators are not compensated for generation curtailed in the model. Because LCOE is the minimum average price required, this estimate of generator benefits represents a lower bound on the annual generator benefits that would be feasible to serve the required load. The total benefits to generators are computed by summing over all generators using the following equation:

$$Benefit_{generators} = \sum_{j=1}^{J} Benefit_j = \sum_{j=1}^{J} LCOE_j \times Generation_j - Cost_j$$

Transmission owner benefits are estimated as the annual revenue given to the transmission owners. In practice, transmission owners are remunerated through a variety of payment mechanisms that vary across jurisdictions. The study team did not model a formal transmission sale market, so the team used the annual revenue requirement for the transmission capital. The annual revenue requirement is the amount of revenue that a capital investment requires to attract the initial financial capital needed to build the infrastructure (Becker 2022). This ensures the transmission owners receive sufficient revenue to build the transmission capital in the modeled scenarios. Similar to using LCOE to model generator revenue, this assumption represents a lower bound on the annual benefit for transmission owners. Annual revenue requirements are computed using the following equation:

$$Benefit_{transmission\ owners} = Transmission\ Capital\ Cost \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where $r$ is the discount rate and $n$ is the expected lifetime of the infrastructure. The study team used $r = 5\%$ and $n = 40$ years for transmission capital.

The study team assumed the power purchaser benefits are equal to the total load benefits minus total load payments. The total load benefits represent the overall economic benefit to end consumers from all electricity uses. The total load benefit is a large quantity that is outside the scope of this study to estimate. When the total load benefit is equal across the scenarios being compared, taking the difference to estimate the relative benefits of the scenarios results in the total benefit term exactly to zero. When this holds, the relative power purchaser benefit simplifies to the avoided cost in load payments. The critical assumption required for the total load benefit to be equal across scenarios is that load demand is the same across the cases being compared, and this assumption is held true within the production cost modeling input assumptions. The power purchaser payment is the sum of payments to generators and payments to transmission owners.

The final stakeholder considered are the taxpayers. The PTC subsidy is paid for broadly by the taxpayer base. This study does not model any formal tax policy regarding tax brackets and assumes taxes are paid when the subsidies are paid. This avoids assumptions about whether the subsidies are paid through government debt or some other mechanism. This simplifies the analysis so the taxpayer benefit is the avoided

cost of subsidy payments. If tax payments increase between scenarios that are compared, this manifests as a negative benefit to the taxpayers.

The annual benefit for each network user for each scenario is the difference between the AC and MT-HVDC transmission scenarios compared to the Limited scenarios; i.e., for each network user *j,* their benefit is calculating using:

$$\text{Benefit}_{i,j} = \text{Cost}_{Lim,j} - \text{Costs}_{\text{i,j}}\ i \in \{\text{AC, MT-HVDC}\}.$$

# 3 Contiguous U.S. Results for Nodal Scenarios

This section presents the study team's results of the nodal transmission portfolios for the contiguous United States for the model year 2035, with emphasis on the resulting transmission plans and the operations of these systems.[35] The study team finds there are several transmission portfolios that can meet the hourly balancing needs of a high renewable energy scenario and, with increased interregional transmission, imports and exports can have large impacts on some regions—resulting in exchanges that exceed the total demand of these regions.

## 3.1 A Range of Transmission Topologies Enables High Levels of Decarbonization

The Z2N translation of ReEDS scenarios demonstrates how a range of transmission topologies and technologies can be used to meet long-term resource changes. This is demonstrated in three scenarios modeled at a nodal level—Limited, AC, and MT-HVDC (and summarized in Table 6 and Table 7).[36] Transmission provides benefits for reaching high levels of decarbonization in a country with substantial amounts of regional diversity in generation resources and across scenarios that analyzed a range of strategies for system growth, transmission topologies, and technology choices. The three nodal scenarios demonstrate interregional or intraregional work in tandem to enable power to move around the country and substantial amounts of both types of transmission are seen in the transmission expansions.

In the Limited scenario, transmission is maximized at the regional level, building on existing high-voltage alternating current (HVAC) networks in the regions. The AC scenario portfolios find local transmission is still important and in need of expansion, but interregional transmission plays a much bigger role—especially in areas of the country where large amounts of new resources are added or where existing HV transmission networks are less developed and interconnected. The need for large expansions of interregional transmission in some regions necessitates voltage overlays (Southwest Power Pool [SPP], MISO, WestConnect) but, in many instances, expansions using existing voltage levels is sufficient.

The MT-HVDC scenario is a very different paradigm compared to systems dominated by HVAC transmission expansion. The HVDC expansions are all long-distance and connecting between neighboring regions, or farther. In addition, the HVDC is largely embedded within AC networks that do not have any experience with HVDC, signifying new operational frameworks would need to be created to handle a very different operating regime. Some regions—such as SPP, MISO, WestConnect, and ERCOT—have substantial enough buildouts of HVDC that it could play a large role in balancing supply and demand. Considering the scale of HVDC expansion envisioned in this study,

[35] All results in Section 3 are from the final ReEDS scenarios, which are inclusive of Inflation Reduction Act impacts and other advances in the ReEDS model. See Chapter 2 for more details on the final ReEDS scenarios.
[36] Further detailed findings from each scenario are provided in Figure B-45, Figure B-46, and Figure B-47 in Appendix B.4.

efforts toward technological standardization and institutional coordination relative to existing practices would be necessary.

The following sections explore the diversity of network portfolios and resulting key messages identified for the three scenarios derived from the application of the Z2N methods and sets of tools described in Section 2. These takeaways are organized into disaggregation (demand, generation, storage), transmission expansion and system operations (focused on transmission) to underscore how transmission growth enables multiple pathways and can support regionally specific solutions for transformative futures.

Table 6. Summary of Common Themes Across Nodal Scenarios

| **Common Themes Across Nodal Scenarios**<br><br>(Limited, AC, MT-HVDC) |
|---|
| - Reinforcement (single-circuit to double-circuit) and/or reconductoring of existing transmission lines occurs in most regions.<br><br>- Increased meshing of existing networks improves contingency performance and collects large amounts of renewable energy from remote parts of existing networks.<br><br>- Development of intraregional transmission networks primarily uses existing voltage levels but with state-of-the-art high-capacity tower and conductor configurations.[37]<br><br>- Reconductoring is a possible solution for some areas where single-circuit to double-circuit expansions are undertaken and part of the transmission network is reaching end of life and will need to undergo modernization.<br><br>- Significant amounts of new renewable energy and storage in parts of the country where there is little to no HV/EHV transmission network infrastructure creates conditions where specific network topologies to collect resources at HV levels could be a good solution and were implemented in these transmission portfolios.<br><br>- Although explicit transmission technology choices and expansion constraints define each transmission portfolio, if further HVDC is implemented at scale, AC and HVDC transmission networks will need to coexist. This results in additional needs for coordination of flows between new AC and HVDC corridors, embedded HVDC corridors, and MT as well as meshed HVDC networks. |

[37] With the implicit interregional focus of the NTP Study (characterized by the need for high-capacity interregional transfers across long distances), the use of high-capacity towers and conductor configurations was an exogenous decision in the modeling after confirming with technical stakeholders this was a valid path forward. It is possible in some corridors these configurations are not necessary or feasible.

Table 7. Summary of Differentiated Themes for Each Nodal Scenario

| Differentiated Themes Across Nodal Scenarios | | |
|---|---|---|
| **Limited** | **AC** | **MT-HVDC** |
| - Substantial amounts of HVAC transmission are expanded within transmission planning regions to enable integration of new VRE capacity usually located far from main load centers.<br>- Intraregional transmission expansion using existing voltage levels for most regions provides sufficient enabling transfer capacity to move power to load centers within regions and to adjacent regions.<br>- Further enabling intraregional expansion in some regions requires the introduction of new EHV voltage levels (voltage overlays), i.e., mostly shifting from 230 kV to 345 kV and 345 kV to 500 kV (minimal new voltage overlays to 765 kV).<br>- Reinforcement and/or reconductoring of existing transmission lines can be a proxy for single-circuit to double-circuit expansions in specific areas (particularly where transmission networks are older). | - Definitive need for substantial amounts of new high-capacity, long-distance, EHV transmission for further connecting transmission planning regions.<br>- Further expanding existing 765-kV AC networks (relative to 500-kV interregional expansions).<br>- Contingency performance when further expanding 765-kV networks (as a large contingency) is important when designing transmission expansion portfolios, i.e., need for supporting existing and potentially new 230-kV, 345-kV, and 500-kV networks under contingency conditions.<br>- In areas where 230-kV and/or 345-kV networks form the transmission grid, high-capacity 500-kV AC transmission seems a good option for expansion. Single-circuit to double-circuit or increased network meshing at existing voltage levels does not prove sufficient.<br>- Considering the volumes of interregional flows, increased coordination between regions (for generation dispatching needs) is expected to operate future systems in the most economical manner while maintaining system reliability.<br>- Series compensation of new EHV capacity for particularly long distances (e.g., Western Interconnection) is implicit in the transmission expansion solutions. However, this was not explored in detail and would need to be further investigated considering large amounts of inverter-based resources. | - HVDC expansion portfolios establish the starting points for MT and potentially meshed HVDC networks. Hence, the significant expansion of high-capacity, long-distance interregional HVDC transmission is based on bipolar, multiterminal/meshed-ready HVDC technologies.<br>- Expanded HVDC performs the role of bulk interregional power transfers whereas HV and EHV embedded AC transmission (existing and in some cases expanded) fulfills a supplementary role in interregional transfers while simultaneously supporting contingency performance.<br>- Large amounts of intraregional HVAC networks are expanded (with similar voltage levels as currently being used/planned) to enable infeed to and from HVDC converter stations.<br>- High coordination levels between regions and across interconnects is expected to operate future systems in the most economical manner (for generation dispatch and HVDC dispatch) while maintaining system reliability. |

Across the nodal scenarios, the expansion of transmission is always substantial. The Limited scenario has the least amount of expansion in all metrics—total circuit-miles, thermal capacity, and the combination of these calculated as terawatt-miles (TW-miles) of transmission. However, the differences between the two accelerated transmission scenarios—AC and MT-HVDC—shifts depending on the metric considered. The circuit-miles are relatively close (~73,000 miles and ~69,800 miles, respectively) whereas thermal capacity or TW-miles is significantly less for the MT-HVDC scenario, primarily because in the MT-HVDC scenario there are relatively long lines that make the miles metric closer. But the HVAC transmission buildout in the AC scenario is substantially more in the combined capacity and distance metric because the scenario includes more shorter-distance HVAC expansions (178 TW-miles in the AC; 80 TW-miles in the MT-HVDC). Further details on these findings are provided in Appendix B.4.

## 3.2 Translating Zonal Scenarios to Nodal Network Scenarios

### 3.2.1 Scale and dispersion of new resources is unprecedented

Based on ReEDS outputs, the scale and geographic dispersion of new generation and storage resources that must be integrated into the U.S. grid in the NTP Study nodal scenarios is unprecedented. Figure 12 shows the total installed capacity by interconnect[38] for the nodal scenarios; Figure 13, Figure 14, and Figure 15 show the nodal POIs (allocation of capacity to specific substations) for the three scenarios after the disaggregation stage of the Z2N process.

The geographical dispersion and scale of new resources are the primary drivers of resulting transmission network expansion portfolios. The scenarios that allow for interregional transmission expansion—AC and MT-HVDC—build more capacity and hence have a substantially larger number of POIs and larger-capacity POIs (larger HV network injections), especially in the middle of the country where large amounts of land-based wind and solar PV are deployed. The MT-HVDC scenario is the least-cost electricity system plan for the three scenarios, followed by the AC and then the Limited scenario.[39] Savings in the MT-HVDC come in the form of reduced generation capital and storage capital costs followed by reductions in fuel costs.

[38] Further details of the installed capacity by transmission planning region and interconnection as well as CONUS-wide for each scenario are provided in Appendix B.4.
[39] Electricity system costs of these scenarios as well as their relative differences in quantum and composition refer to the results from the zonal scenario analysis in Chapter 2.

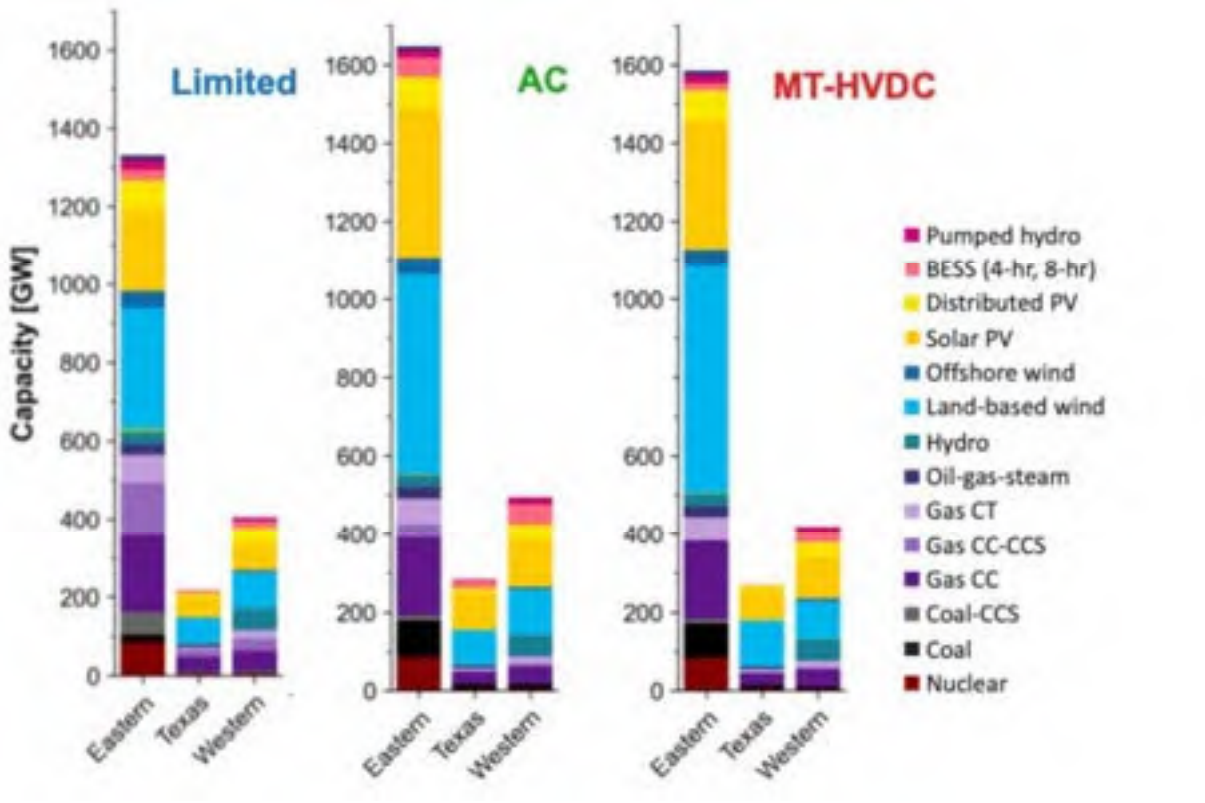



Figure 12. Generation and storage capacity for final nodal scenarios

The Limited scenario exhibits the least amount of installed capacity mostly because it includes the least amount of land-based wind and solar PV (465 GW and 453 GW, respectively) whereas a large amount of existing and new gas-fired and coal-fired capacity are retrofitted for coal capture and storage (CCS) operations (~182 GW and ~70 GW, respectively). As a reminder, the lower level of total installed capacity in this scenario is driven by capital costs for retrofits and new capacity as well as fuel (and to a lesser extent by operation and maintenance cost differences).[40] This is less evident in the AC and MT-HVDC scenarios where existing coal and gas capacity remains online and a smaller proportion is retrofitted for CCS operations (12–13 GW and 5–40 GW, respectively). There is 64 GW of battery energy storage system (BESS) capacity installed in this scenario, which is a substantial ramp-up from what is currently installed across CONUS but is substantively less than the AC scenario.

The AC scenario with the ability to expand interregional transmission via HVAC technologies (within the same interconnection) shows a significantly larger expansion of land-based wind and solar PV capacity (714 GW and 730 GW, respectively) and fewer CCS retrofits of fossil generation capacity (coal and gas). Much of the wind capacity is developed in the central wind belt of the country—in the Midwest (MISO region), along the Great Plains (SPP region), in parts of the Northeast and Rocky Mountains

[40] See Chapter 2, Section 3 for further details. Maps summarizing the zonal transmission expansion for the three nodal scenarios are presented in Chapter 2 but are also provided for reference in Appendix B.4.

(NorthernGrid and WestConnect regions), and in west Texas (ERCOT West). For solar PV, a large amount of capacity is concentrated in the Southeast (Southeastern Electric Reliability Council and Southeastern Regional Transmission Planning [SERTP] regions), parts of ERCOT, and the Desert Southwest (WestConnect region). There is ~130 GW of BESS capacity installed in the AC scenario (almost twice as in the Limited scenario).

The MT-HVDC scenario—with the ability to expand HVAC within interconnects and expand HVDC within interconnects and across seams—exhibits larger amounts of land-based wind (770 GW) and solar capacity (600 GW) compared to the Limited scenario but with a shift toward more land-based wind relative to solar PV capacity. As will be demonstrated further in the following sections, there is a distinct correlation of wind capacity expansion with increased interregional transmission. This is driven by the clear trade-offs between long-distance, high-capacity transmission expansion and wind resource expansion to move power from distant locations toward load centers.

All scenarios include offshore wind capacity of 47 GW being deployed by 2035 with most of this concentrated off the Atlantic coast (42 GW) and the remainder off the Pacific coast (~5 GW). These scenarios are based on assumed mandated offshore wind deployment targets set by state renewable portfolio standard policies. Offshore transmission network design options are not the focus of the NTP Study. Instead, land-based network expansion needs are established based on POIs correlated as much as possible with other similar efforts led by DOE (Brinkman et al. 2024).

Across the three nodal scenarios, a significant amount of new generation capacity is built in areas with very limited existing HV/EHV transmission capacity—that is, northern parts of SPP (Nebraska, South Dakota), MISO (Minnesota), Southern SPP (Oklahoma, Texas panhandle), eastern parts of NorthernGrid (Montana), and in the south of WestConnect (New Mexico). This necessitates significant development of HV/EHV transmission infrastructure because limited interregional HV/EHV transmission exists in these regions to enable a combination of collector networks of the many POIs (mostly VRE sources) or direct interconnection of large POIs to bulk transmission backbones for transfers to main load centers.

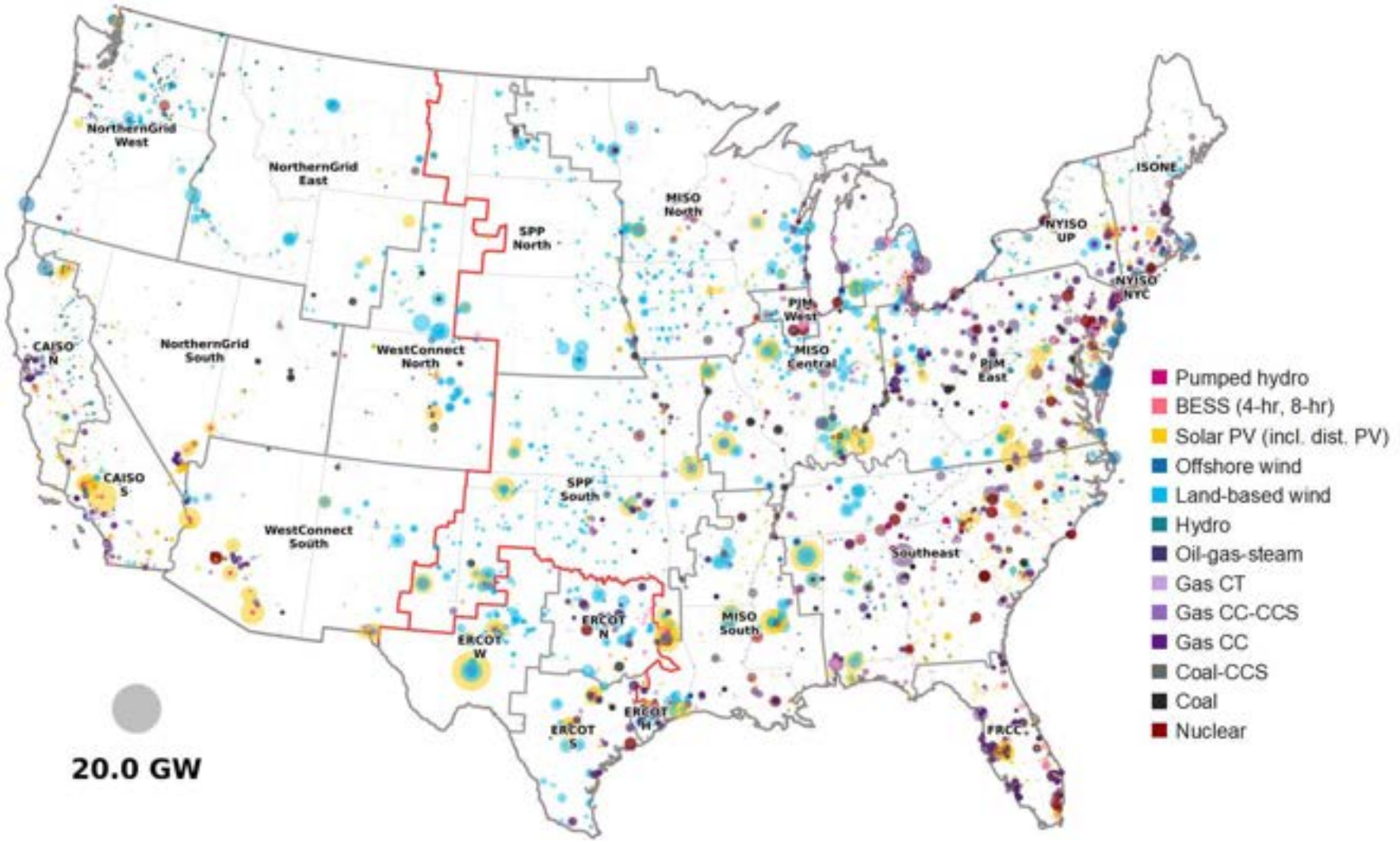



Figure 13. Nodal POIs, sized by capacity, for all generation types for the Limited scenario

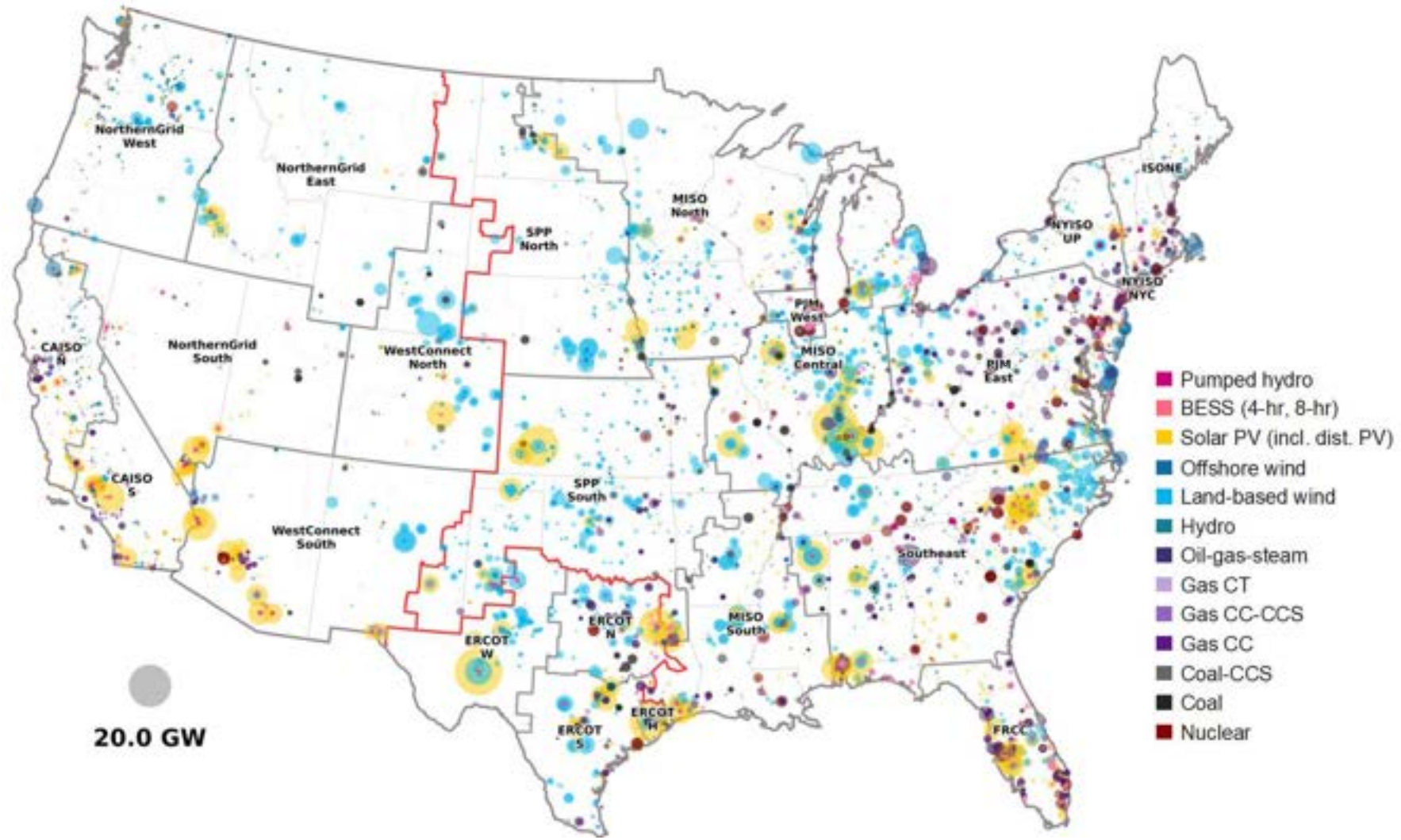



Figure 14. Nodal POIs, sized by capacity, for all generation types for the AC scenario

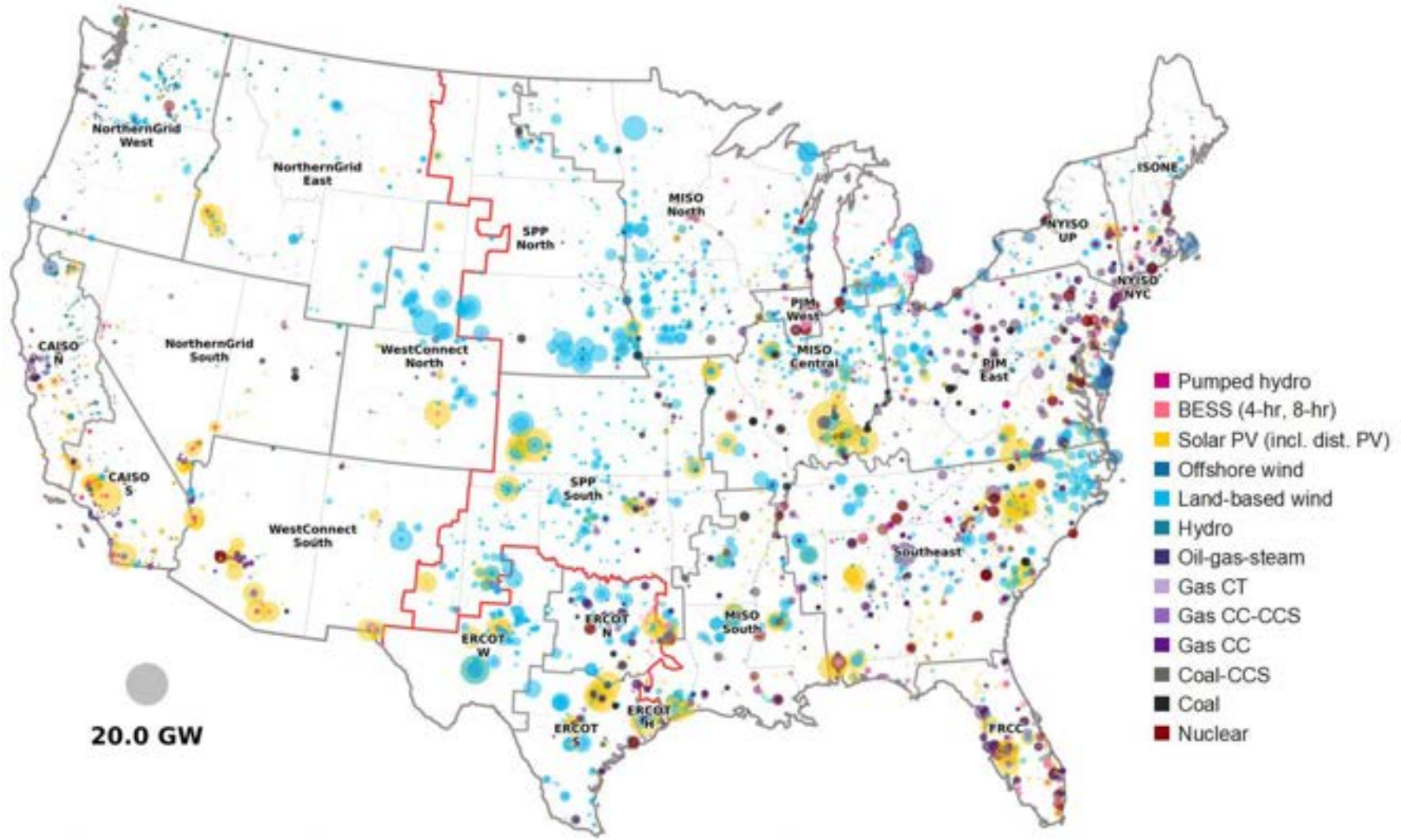



Figure 15. Nodal POIs, sized by capacity, for all generation types for the MT-HVDC scenario

### 3.2.2 Intraregional transmission needs are substantial, especially when interregional options are not available

In the Limited nodal scenario, additional transmission is 77 TW-miles by 2035,[41] which is 1.3 times the TW-miles of the existing industry planning cases.[42] New transmission consists of local interconnection for new resources at the bulk level as well as the enabling transit capacity to move power across nonadjacent regions to enable the integration of new capacity usually located farther from main load centers. Figure 16 shows the spatial mapping of the Limited scenario nodal transmission portfolio.[43]

Transmission portfolios predominantly include new circuits in parallel with existing circuits and some selected new intraregional paths via double-circuit additions to enable a nodal solution that meets the decarbonization objectives envisioned in this scenario. Hence, preexisting voltage levels within specific regions are generally maintained.

As shown in Figure 16, the intraregional nodal HVAC transmission needs in the Limited scenario are still substantial.[44] Local interconnection is most prevalent for new resources at the bulk level as well as the enabling transit capacity to move power across nonadjacent regions to enable the integration of new capacity usually located farther from the main load centers. These intraregional expansions are particularly notable in the southern parts of SPP, in PJM, and in northern parts of WestConnect.

[41] It is worth noting with a caveat that this nodal transmission portfolio expansion is higher than the corresponding ReEDS zonal expansion by 2035 (considering 1.83 TW-Miles/year constraint).
[42] Industry planning cases for this study are compiled based on planning cases for 2030-31 (Table 3).
[43] Table B-21, Table B-22, and Table B-23 in Appendix B.4 provide further detailed findings of the nodal transmission solutions for this scenario.
[44] A few instances of interregional transmission strengthening were required in the Limited scenario. This is for many reasons, such as the geographic zonal designations in ReEDS and the placement of new generation capacity (mostly wind or solar) in locations that are geographically in one zone but, when mapped to a nodal network model, could be closer to another zone and therefore cause congestion as a result of network impedances being represented (and not as a zonal transportation model as in ReEDS). In general, the intention of the ReEDS Limited scenario was maintained with very few interregional expansions.

Figure 16. Nodal transmission expansion solution for the Limited scenario for model year 2035

### 3.2.3 Achieving high levels of interregional power exchanges using AC transmission technologies requires long-distance, high-capacity HV corridors combined with intraregional reinforcements

In the AC nodal scenario, where transmission infrastructure increased to 179 TW-miles (by 1.7 times the TW-miles by 2035 from the 2030/2031 industry planning cases), regional diversity of resources plays an important role when designing nodal transmission expansion portfolios. Figure 17 shows the spatial mapping of the AC nodal transmission expansion developed for the NTP Study.[45]

Transmission systems in much of the Southeast have a strong 500-kV backbone and underlying 230-kV networks (particularly in the eastern parts of the Southeast). These are used for the integration of predominantly new VRE generation capacity, including in the Carolinas and Georgia and stretching into Florida. Clusters also exist in Southern and Central Alabama as well as Tennessee. In the AC scenario, the expansion of the 500-kV network into the Midwest and farther west into the Plains enables the movement of large volumes of power across several interfaces north-south and west-east to load centers. This is enabled by existing 345-kV networks in the Midwest and Plains (MISO; SPP) that are further strengthened and link with the 500-kV networks in the Southeast.

In the Northeast, solutions for expansion are selected increases in transfer capacity on existing 345-kV networks. In PJM, there is strengthening of the existing 765-kV networks as well as creating further 500-kV links to the Southeast and along the Eastern Seaboard (increasing the capabilities for large north-south transfers across longer distances).

In the Western Interconnection, 500-kV overlays and new transfer paths at 500 kV in NorthernGrid and WestConnect help carry resources across long distances. Northern California Independent System Operator (CAISO) solutions include further 500 kV for interregional exchanges with NorthernGrid (Oregon) and to integrate West Coast offshore wind capacity.

In ERCOT, the existing 345-kV networks are strengthened by creating double-circuit 345-kV paths in existing single-circuit paths while creating new paths to bring wind and increased amounts of solar from western and northern Texas toward load centers in Dallas-Fort Worth, Austin, and Houston. There is not a strong case for new voltage overlays (toward 500 kV), and HVDC is precluded from this scenario as an expansion option.

When expanding interregionally, each region of the CONUS grid exhibits characteristics that influence network expansions. Significant amounts of new wind, solar PV, and storage in parts of the country where there is little to no HV/EHV transmission network infrastructure available opens the possibility for the design of specific network topologies to connect large concentrations of resources at HV levels to integrate into long-distance transmission corridors. This is a departure from the incremental

[45] Table B-23 in Appendix B.4 provides further detailed findings of the nodal transmission solutions for this scenario.

interconnection of relatively smaller VRE plants at subtransmission voltage levels (particularly solar PV and less for land-based wind). Areas where this is pertinent from the findings of the NTP Study are the far northern and far southern parts of SPP, WestConnect, parts of northern MISO, Florida Reliability Coordinating Council (FRCC), and western and northern parts of ERCOT.

The scale of interregional power exchanges that form part of the AC scenario requires some regions to develop high-capacity transmission infrastructure that enables transfer flows. More specifically, regions such as MISO act as a transfer zone between SPP and PJM whereas, similarly, the Southeast and PJM act as enablers of transfer flows for FRCC and the Northeast (Independent System Operator of New England [ISONE]/New York Independent System Operator [NYISO]), respectively.

The portfolios this section describes are a single implementation of interregional transmission. Hence, it is feasible a range of alternative transmission portfolios may provide similar technical performance where intraregional transmission needs could be further identified and refined and region-specific planning expertise could add value to the portfolios presented.

Figure 17. Nodal transmission expansion solution for the AC Scenario for the model year 2035

### 3.2.4 HVDC transmission buildout represents a paradigm shift and includes the adoption of technologies currently not widespread in the United States

The 2035 MT-HVDC scenario transmission design results in 128 TW-miles of additional transmission (a 1.5 times increase in TW-miles from the 2030/31 industry planning cases). This includes 48 TW-miles of HVDC and 80 TW-miles of HVAC. The total thermal capacity of HVDC expansion by 2035 is 156 GW.[46] The spatial mapping of the transmission solution is shown in Figure 18.[47]

The HVDC expansion enables substantial ties between the three U.S. interconnections, which currently have about 2.1 GW of transfer capacity (1.3 GW between the Eastern Interconnection and Western Interconnection and about 0.8 GW between the Eastern Interconnection and ERCOT). Seam-crossing capacity is 46 GW, deployed through 12- x 4-GW bipoles and a 1- x 2-GW monopole. Most of this is between the Eastern Interconnection and Western Interconnection (22 GW), further interconnecting WestConnect and SPP as well as NorthernGrid and SPP. The Eastern Interconnection and ERCOT capacity increases to 20 GW whereas the Western Interconnection and ERCOT are connected via two HVDC links totaling 8 GW. The expanded ties between ERCOT and the Western Interconnection are particularly highly used (~91%) and unidirectional (power flowing from ERCOT to the Western Interconnection). The expanded ties between Western Interconnection and Eastern Interconnection are bidirectional and have a utilization of ~40%.

Within the Western Interconnection, the beginnings of an MT and meshed HVDC network is realized at a nodal level via 20 GW of HVDC capacity (5 by 4 GW, excluding seam-crossing capacity), connecting large amounts of wind and solar PV in the southern parts of WestConnect to the northern parts of WestConnect and CAISO.

In the Eastern Interconnection, 90 GW of HVDC are built (18 by 4 GW and 1 by 2 GW). These HVDC links enable power to be moved from the predominantly wind-rich areas of northern SPP and MISO eastward, with the confluence in the central parts of MISO and PJM. The shifting of power between southern parts of SPP, southern MISO, and the Southeast is enabled via 16 GW (4 by 4 GW) of MT long-distance HVDC links where 8 GW of HVDC continues toward the FRCC region.

The development of the interregional HVDC transmission overlay that comprises the MT-HVDC scenario also requires significant development of intraregional HVAC networks to enable power infeed to and from HVDC converter stations. These can be seen in the map in Figure 18 where HVAC networks around HVDC terminals are expanded or increasingly meshed or, in some cases, new voltage overlays are developed to support the scale of infeed and/or export from HVDC converter stations. Hence, most of the HVAC expansion is via voltage levels already present in each region

[46] For the HVDC buildout process, the study team used discrete building blocks: 2 GW monopole or 4 GW bipole. These configurations were used as needed and terminated into strong areas of AC networks. Appendix A.5 provides further details on the HVDC transmission expansion philosophy.
[47] Table B-23 in Appendix B.4 provides further detailed findings of the nodal transmission solutions for this scenario.

but in some cases requires new voltage overlays. Examples of a large AC expansion is in WestConnect North, where the existing relatively weak 230-kV and 345-kV networks need strengthening. There are also significant changes to the underlying AC network in southern SPP, where a 500-kV expansion enables additional movement of power from SPP toward southern MISO.

The extent of HVDC transmission expansion in the MT-HVDC scenario combined with the underlying nodal AC transmission expansion has not yet been seen in industry plans in the United States (Johannes P. Pfeifenberger et al. 2023; Bloom, Azar, et al. 2021; Brown and Botterud 2021; Eric Larson et al. 2021; Christopher T. M. Clack et al. 2020; Bloom, Novacheck, et al. 2021) or internationally (European Network of Transmission System Operators for Electricity [ENTSO-E], n.d.; Terna spa, n.d.; National Grid ESO, n.d.; DNV 2024; CIGRE 2019, 775; MEd-TSO 2022; Empresa de Pesquisa Energética [EPE] 2023). Similarly, considering the level of buildout envisioned in the MT-HVDC scenario, features that could ease HVDC growth over the coming decades include the implementation of MT and meshed-ready technology deployments; common design principles and standardized HVDC voltage levels, communications protocols and technology configurations would also be helpful. These were generally assumed to exist in the MT-HVDC nodal scenario. Finally, the operational and institutional coordination necessary in MT-HVDC production cost modeling is beyond what is currently practiced between regions in the United States and may require new approaches to operations via increased coordination at various operational timescales.[48]

[48] Ongoing efforts in the United States and Europe are moving toward standardization of HVDC transmission design and related interoperability (among others). Examples of these include DOE (2023) in the United States and InterOPERA (InterOPERA 2023) in Europe.

**Differences between MT-HVDC nodal scenario and zonal scenario**

As noted in the methodology sections of this chapter, ReEDS results do not provide prescriptive zone-to-zone discrete HVDC lines and converter pairs. When expanding the nodal transmission, the study team made decisions about transmission expansion using ReEDS results as a guideline, in addition to using the nodal industry planning cases network topology, semibounded power flows after disaggregation of generation and storage, and related information that might impact actual network expansion.

For the MT-HVDC scenario, there are many additional challenges beyond those in the Limited and AC scenario in deciding on expansion, including the need to embed HVDC into large and complex HVAC networks where there is limited existing HVDC transmission. Therefore, the study team approached this by using discrete HVDC expansions as a starting point and building out HVAC around this through an iterative process to enable increased use of existing networks. In some cases, express HVDC corridors skipped over ReEDS zones where power was evidently moving through zones instead of using that zone as a source or sink. In practice, these zones could potentially tie into the HVDC line that is passing through via additional converter capacity. In the end, if enough transmission was added to meet the requirements of a reliable system for 2035—balancing supply and demand and enabling generation to move to load centers and meet demand as planned by the ReEDS scenarios—the transmission expansion was considered complete.

The result of this approach is the MT-HVDC nodal scenario exhibits much less new HVDC transmission capacity than seen in the zonal ReEDS scenarios. One of the primary reasons for this is the nodal production cost modeling scenarios are not directly assessing resource adequacy with multiyear weather data (they are run for only one weather year). So, where ReEDS may have seen a substantial amount of resource adequacy benefit over the full 7-year perspective (see Chapter 2), discrete nodal production-cost and power flow models might not capture these trends and potential additional value of transmission. Future work could benefit from verifying network expansions on many future model years with varied weather and further extending the Z2N workflows to additional modeling domains where this value can be captured.

An additional consideration in building out the MT-HVDC scenario is HVDC is applied as a transmission network expansion solution only in cases where it is a clear and obvious solution for long-distance, high-capacity power transfer needs as guided by the ReEDS findings. Therefore, the study team relied on it only when it was clearly the best solution relative to more incremental AC transmission expansion.

For context on the scale of expansion achieved in the MT-HVDC scenario, global HVDC installed capacity by the end of 2023 was ~300 GW (the 10-year pipeline is an additional ~150 GW) (Johannes P. Pfeifenberger et al. 2023). With the full implementation of the nodal MT-HVDC scenario for CONUS alone, the global HVDC market would increase by 50% by 2035.

Figure 18. Transmission portfolio solution for MT-HVDC scenario for the model year 2035

## 3.3 Operations of Highly Decarbonized Power Systems

The following presents results of the annual production cost modeling for the final contiguous U.S. nodal scenarios for the model year 2035.

### 3.3.1 Interregional transmission is highly used to move renewable power to load centers but also to balance resources across regions

Transmission expansion in the AC and MT-HVDC scenarios enables large amounts of power to flow across major interregional interfaces. As seen in the flow duration curves in Figure 19, the scale of power flows between the Southeast and MISO (Central) regions increases in the AC scenario—up to 10.1 GW and ~27 TWh of annual energy—compared to the Limited scenario where only up to 2.6 GW of flow and ~10 TWh of annual energy is exchanged across the interface. Though the dominant contributor to the differences is the magnitude of the interregional transfer capacity, some of this difference is also attributable to the 3%–8% of congested hours where more congestion exists in the Limited scenario relative to the AC scenario (shown by the flat portion of the curves). Further, the predominant flow of power from MISO (Central) to Southeast (70%–75% of the time) indicates low-cost predominantly wind resources in the MISO region (in all scenarios) are consumed in the Southeast for parts of the year. MISO is also a net exporter to PJM, sending a net of 105 TWh annually.

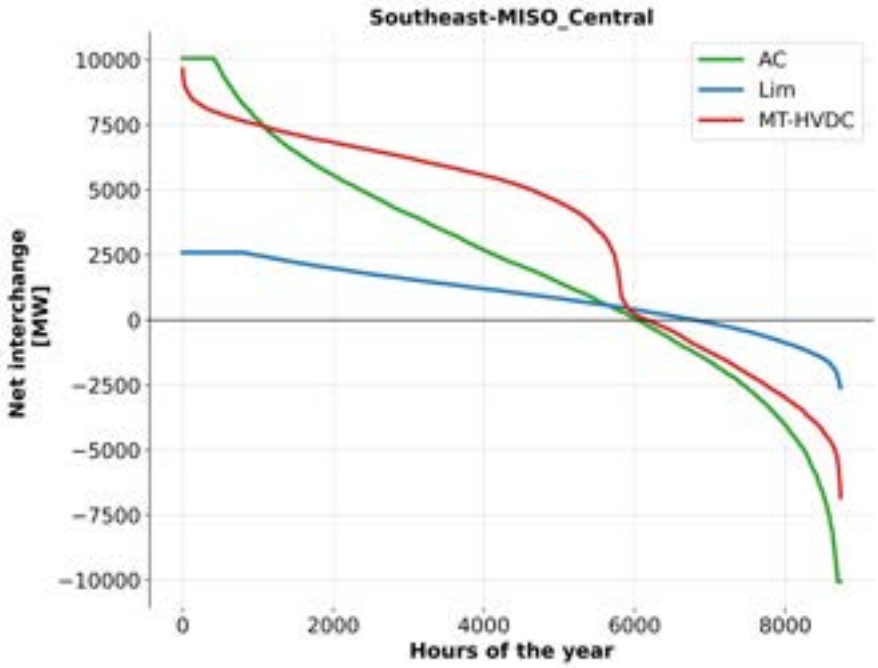



Figure 19. Flow duration curve between MISO-Central and the Southeast

*Positive values indicate power is flowing from MISO-Central to the Southeast; negative values indicate flow from Southeast to MISO-Central.*

In other areas, such as the ties between the Southeast and FRCC, the interregional transmission infrastructure experiences increased average utilization compared to other

interfaces. The lines that comprise the interface between SERTP and FRCC regions play an important role in leveraging diurnal complementarities between solar PV systems and BESS (in FRCC) and combined wind, solar PV, and other dispatchable technologies (in the Southeast). This balancing of resources between regions is demonstrated through the FRCC and Southeast flow duration curves and diurnal flow distributions shown in Figure 20. Although there are larger maximum amounts of power flows between these two regions in the AC relative to Limited scenario, and further larger transfers for the MT-HVDC scenario, there is a difference in the relative distribution of these flows as well as directionality. Figure 22 (b–d) illustrates these differences, showing how large amounts of wind are imported into FRCC during the early mornings and late evenings and solar is exported into the Southeast in the afternoon, using the full capacity of the interface in both directions. This is driven by the increased amount of solar PV in FRCC in the AC scenario. The diurnal flow in the Limited scenario is characterized by a wider distribution of imports and exports but is punctuated by more exports (or relatively lower imports) from FRCC to the Southeast in the morning hours (06h00–10h00) and later evening hours (19h00–21h00), which is particularly pronounced during the spring and summer months (March–August). The annual average dispatch stacks in 2035 are shown in Figure 21 for FRCC and the Southeast (for AC and MT-HVDC scenarios), demonstrating shared resources between these two regions.

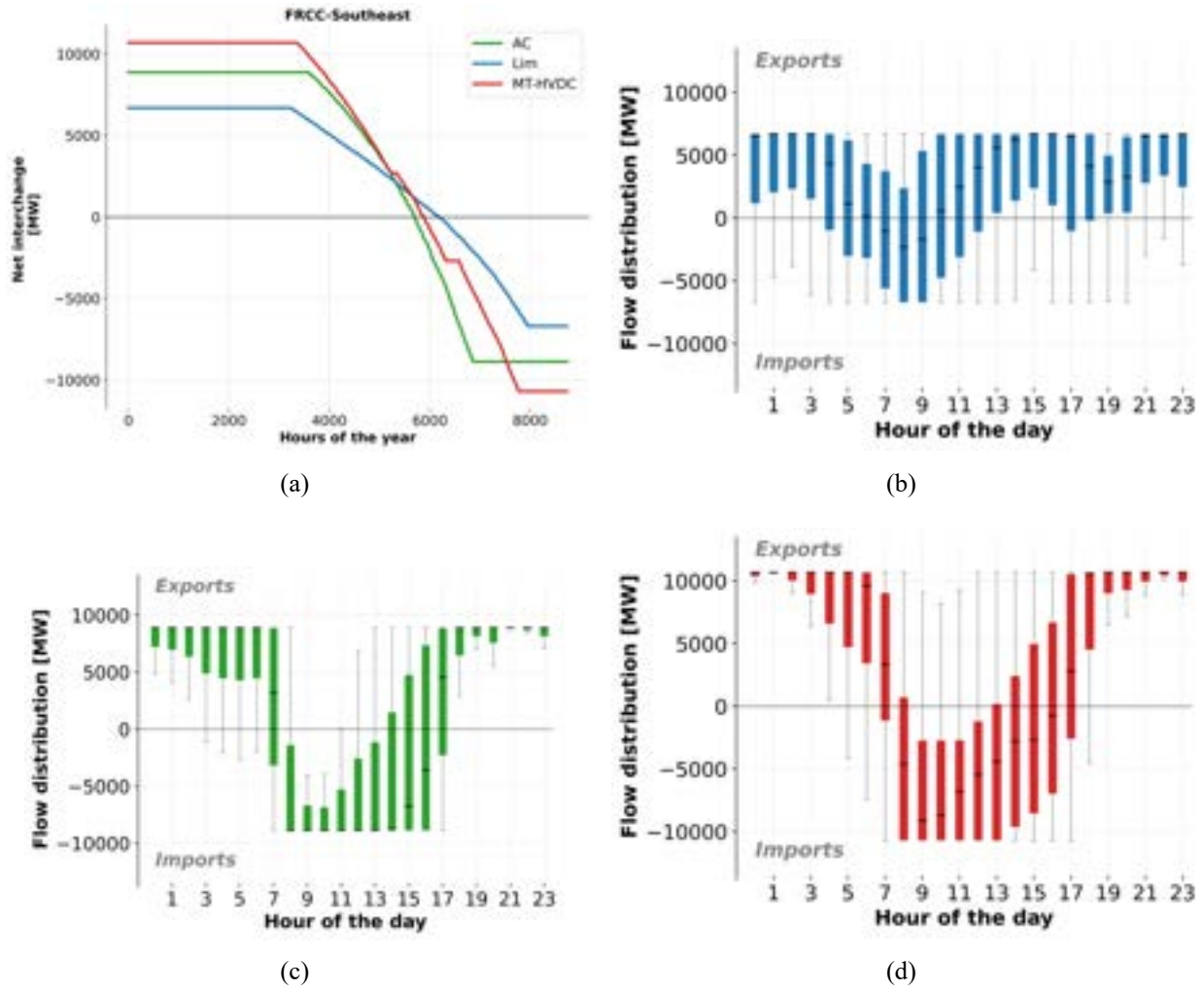
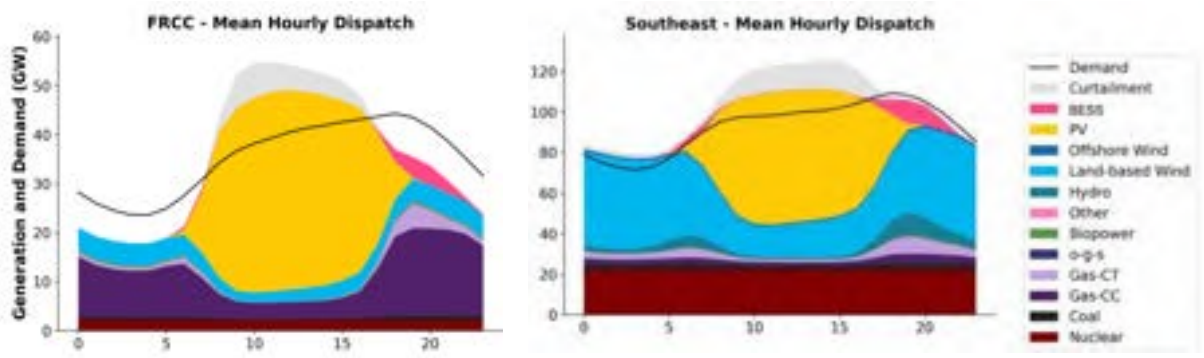
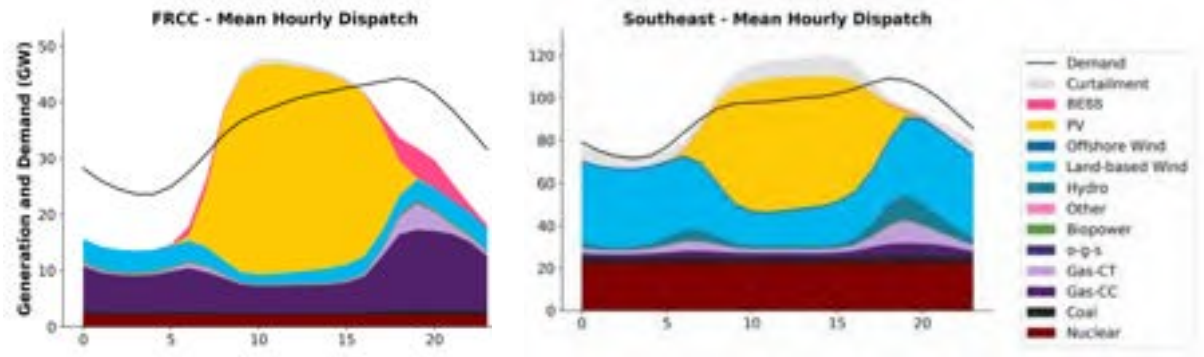



Figure 20. Flow duration curves (a) and distribution of flows (b), (c), (d) between FRCC and the Southeast




(a) AC scenario




(b) MT-HVDC scenario

Figure 21. Dispatch stack for peak demand period in FRCC and Southeast for (a) AC and (b) MT-HVDC

### 3.3.2 Diurnal and seasonal variability may require increased flexibility as well as interregional coordination to minimize curtailment

The Limited scenario exhibits the least amount of curtailment of VRE resources relative to the AC and MT-HVDC scenarios, driven by the combination of more installed wind and solar capacity in the AC and MT-HVDC scenarios (with the same demand) and less interregional transmission. As an example of this, for 15%–22% of the year, there is more energy available from VRE sources than there is demand in the Eastern Interconnection (greater than 1.0 in Figure 22). Consequently, even with no network congestion, oversupply would result in VRE curtailment because there is not enough storage capacity to consume the extra power in all periods (a trade-off established in the zonal ReEDS scenarios between storage investment and operational costs relative to curtailed energy).

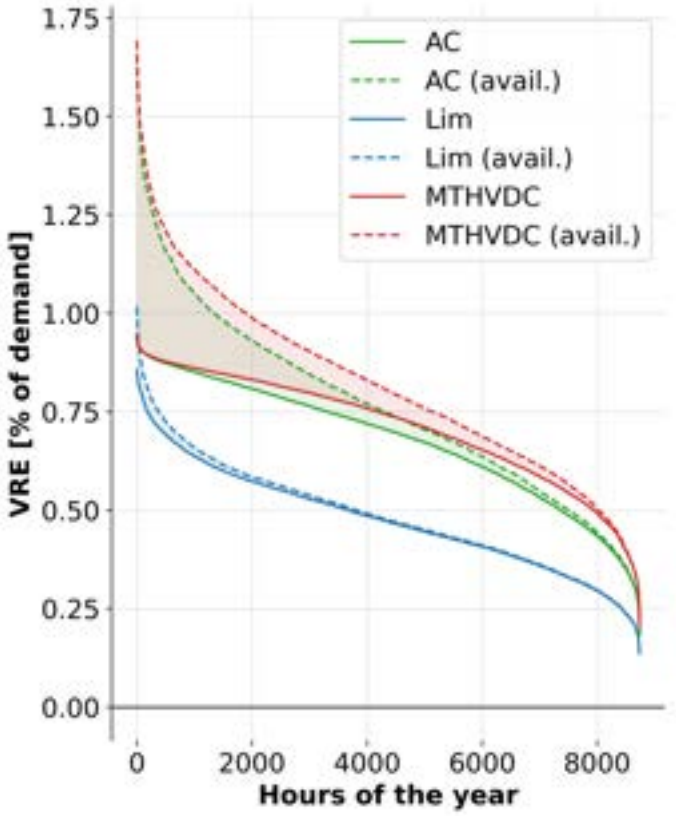



Figure 22. VRE production duration curve (normalized to demand) for the Eastern Interconnection

Figure 23 shows the monthly generation per interconnection for the AC scenario; Figure 24 demonstrates this for CONUS for the MT-HVDC scenario (monthly curtailment can be seen in the light-gray shade). The Limited scenario exhibits monthly curtailment patterns similar to those of the AC scenario but with lower absolute levels (as also indicated in Figure 22). With the large amounts of VRE resources added in scenarios with interregional transmission expansion, curtailment becomes common throughout the year and is particularly higher in regions with disproportionately larger amounts of VRE resources added relative to demand (SPP and MISO in particular). Similarly, the seasonal pattern of curtailment is driven by relatively high wind energy resources in the spring and fall, coinciding with relatively lower demand months (at an interconnection level and CONUS level) combined with lower correlation with the availability of hydro resources throughout other parts of the year.

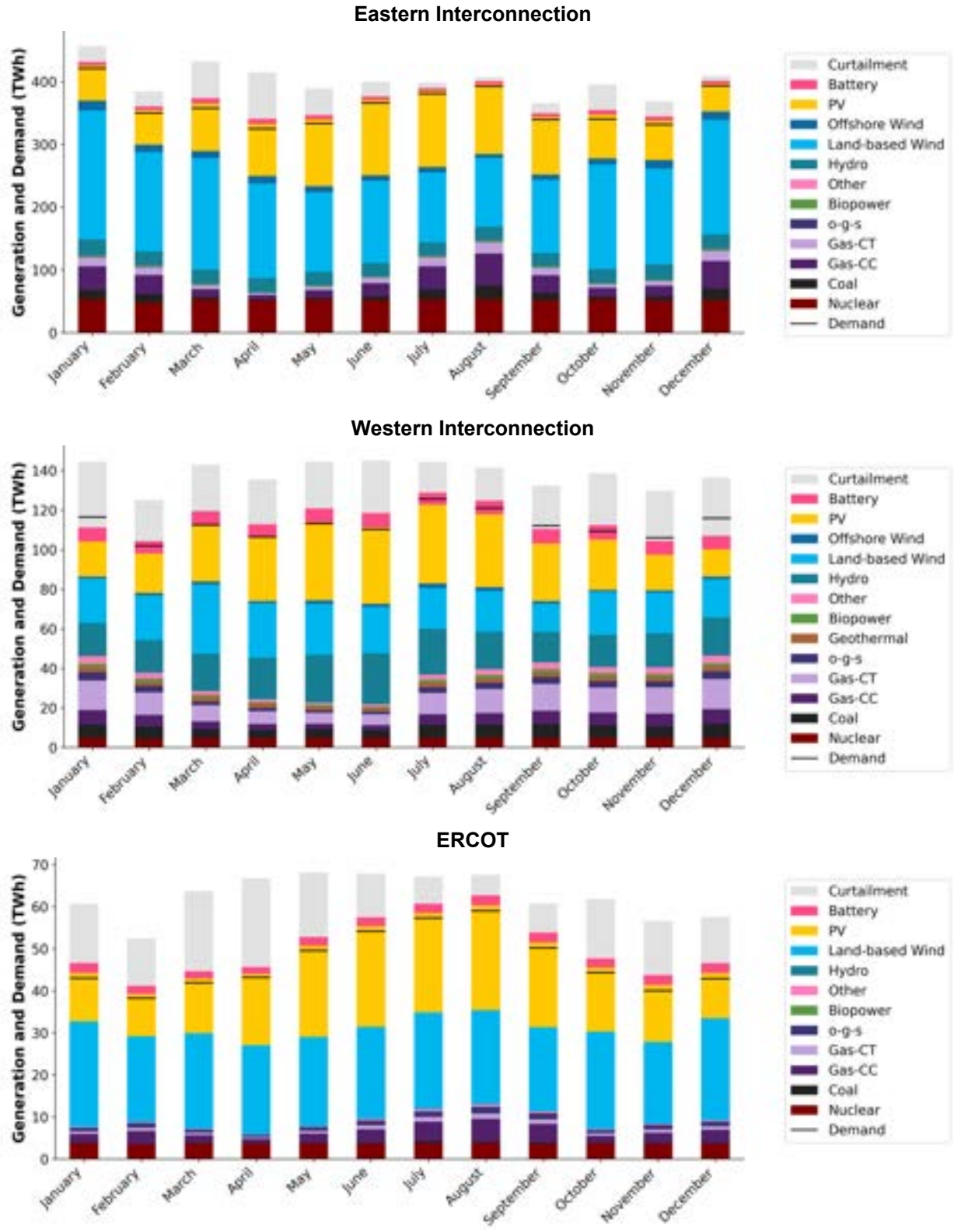
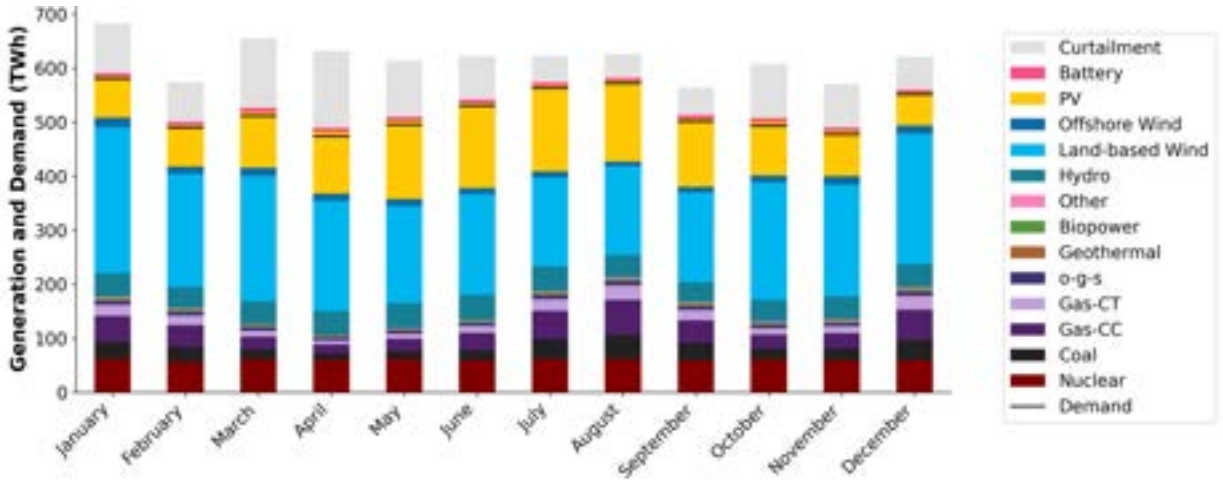
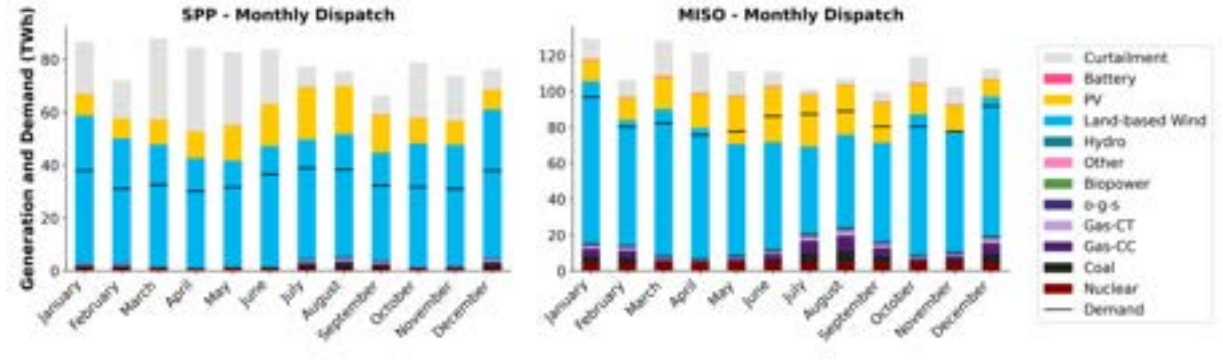



Figure 23. Monthly generation (per interconnection) for the AC scenario

*These demonstrate monthly curtailment patterns (higher curtailment in late winter and early spring); similar trends exist for the Limited and MT-HVDC scenarios.*




(a)




(b) (c)

Figure 24. Monthly generation (CONUS) for (a) MT-HVDC scenario and (b) within SPP and (c) MISO

*Demonstration of monthly curtailment patterns CONUS-wide as well as specific regions with large amounts of installed land-based wind capacity where general trends are highlighted further.*

Dispatch trends demonstrating flexibility needs across the nodal scenarios are demonstrated via dispatch stacks for various seasonal periods for the Limited, AC, and MT-HVDC scenarios in Figure 25, Figure 26, and Figure 27, respectively. As expected, higher levels of curtailment exist in the daytime hours when wind and solar PV are both producing simultaneously and in scenarios where more VRE make up the resource mix (AC and MT-HVDC). This curtailment supports balancing compared to the Limited scenario because of the significantly more wind and solar installed for the same demand even though there is more interregional transmission expansion. The use of short-duration storage resources (in the form of BESS) also plays a large role in balancing, where discharging of storage occurs in some morning hours as demand increases but is mostly concentrated in evening hours after being charged during the day when there is excess wind and solar. This finding is robust across interconnections and scenarios.

The curtailment of VRE is driven primarily by the trade-offs between resources and transmission in ReEDS. Once translated into nodal production-cost models with

improved temporal and transmission networks representation, curtailment emanates further from the combined flexibility characteristics[49] of the complementary fleet of dispatchable technologies and interregional transmission expansion. The fast-ramping nature and low absolute levels of residual demand after wind and solar generators are dispatched are particularly noticeable for BESS, combined cycle gas, and combustion engines where increased unit starts/stops, increased periods of operation at minimum-stable levels, and increased unit ramping are required.

[49] Flexibility is required for increased ramp rates, lower minimum operating levels, and more startups and shutdowns of supply resources to meet residual demand needs (within and across regions).

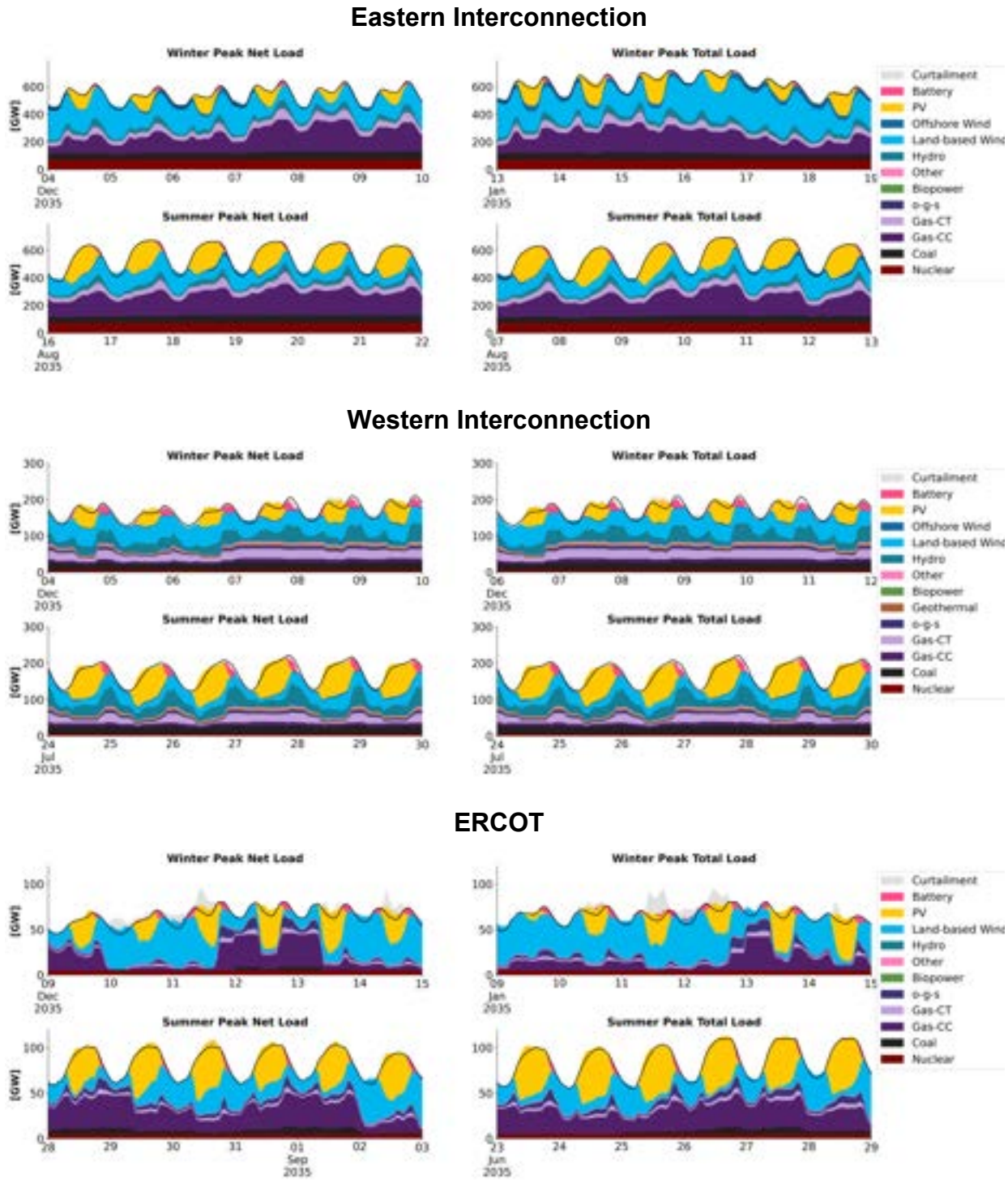



Figure 25. Seasonal dispatch stacks (per interconnect) for the Limited scenario

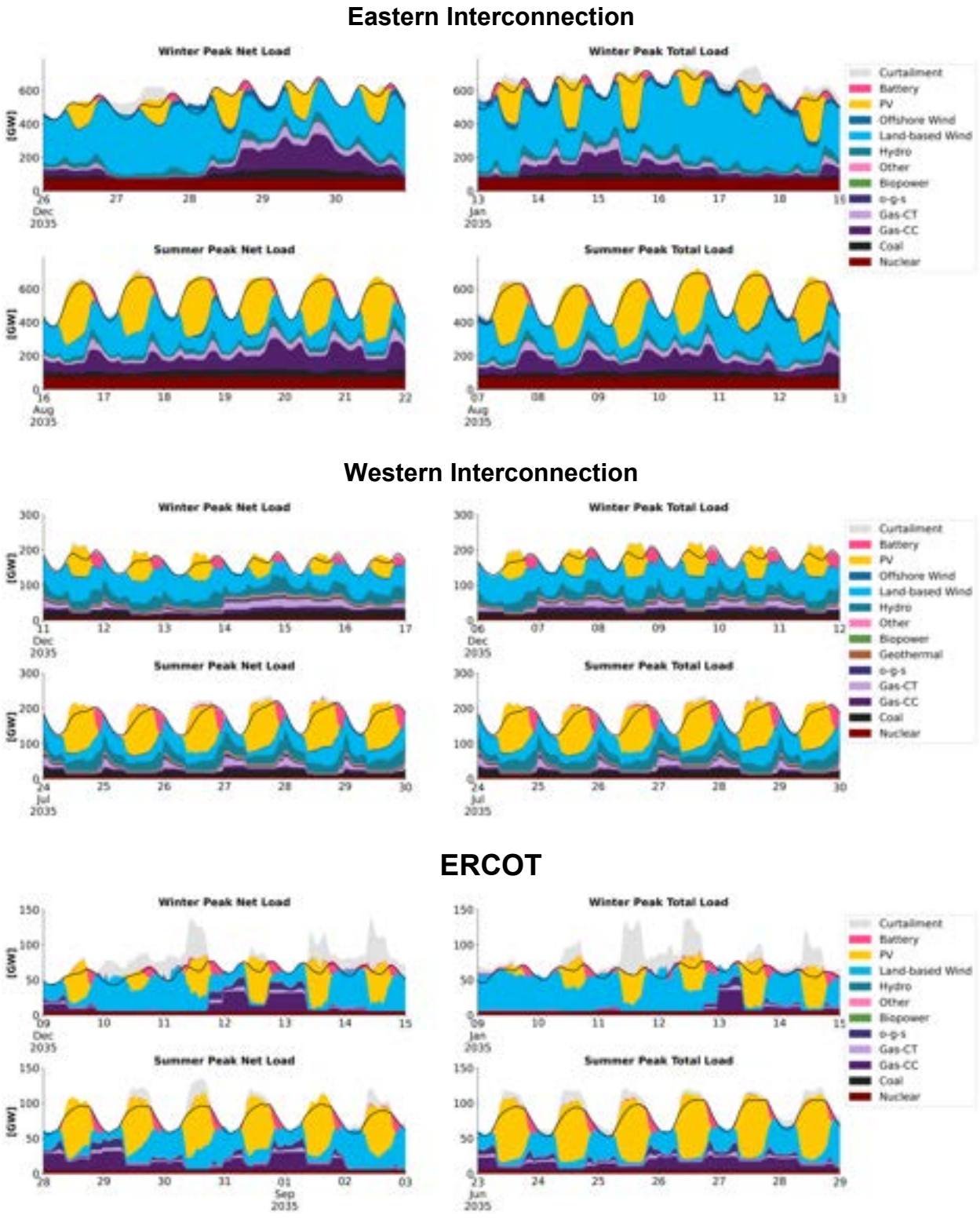



Figure 26. Seasonal dispatch stacks (per interconnect) for the AC scenario

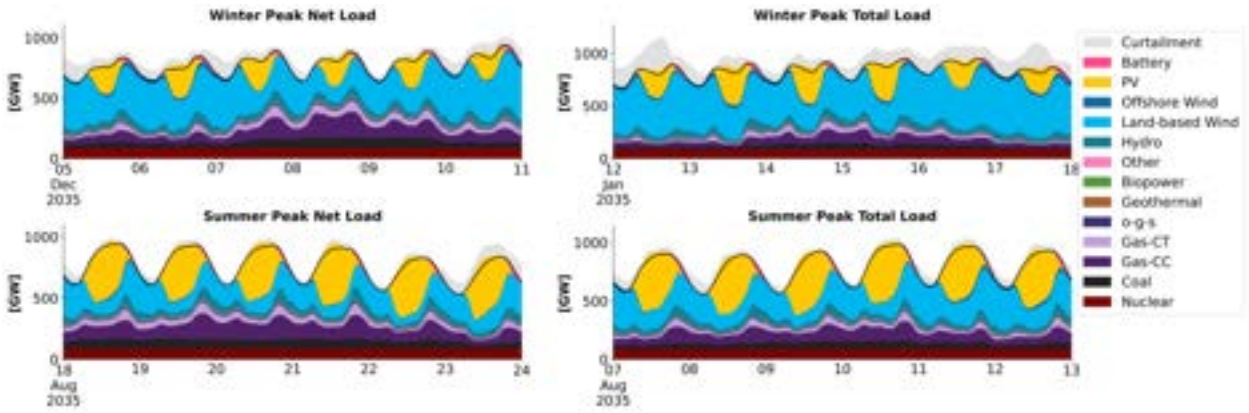



Figure 27. Seasonal dispatch stacks (continental United States) for the MT-HVDC scenario

### 3.3.3 Regions with high amounts of VRE relative to demand become major exporters and often exhibit very low amounts of synchronous generation

The AC and MT-HVDC scenarios represent futures with large amounts of energy transfers between regions as transmission expansion better connects them. This could drastically change the role of certain regions or increasingly solidify their role as large power exporters. For example, as demonstrated for the AC scenario in Figure 28 for a peak demand week in SPP and MISO, large amounts of VRE resources relative to demand exist. This results in large exports of wind and solar (where supply is greater than demand in Figure 28).[50] These exports to other regions result in operating periods with very few online synchronous generating units in the region and large numbers of inverter-based resources (IBRs) in the form of wind and solar generators in operation. These operating periods are important to scope and dimension the scale of mitigation measures and solutions to address stability concerns with such high levels of IBRs and low levels of synchronous generation. However, these mitigation measures and solutions are out of scope for the NTP Study.

[50] Similar patterns with respect to exports of wind and solar also exist in the MT-HVDC scenario.

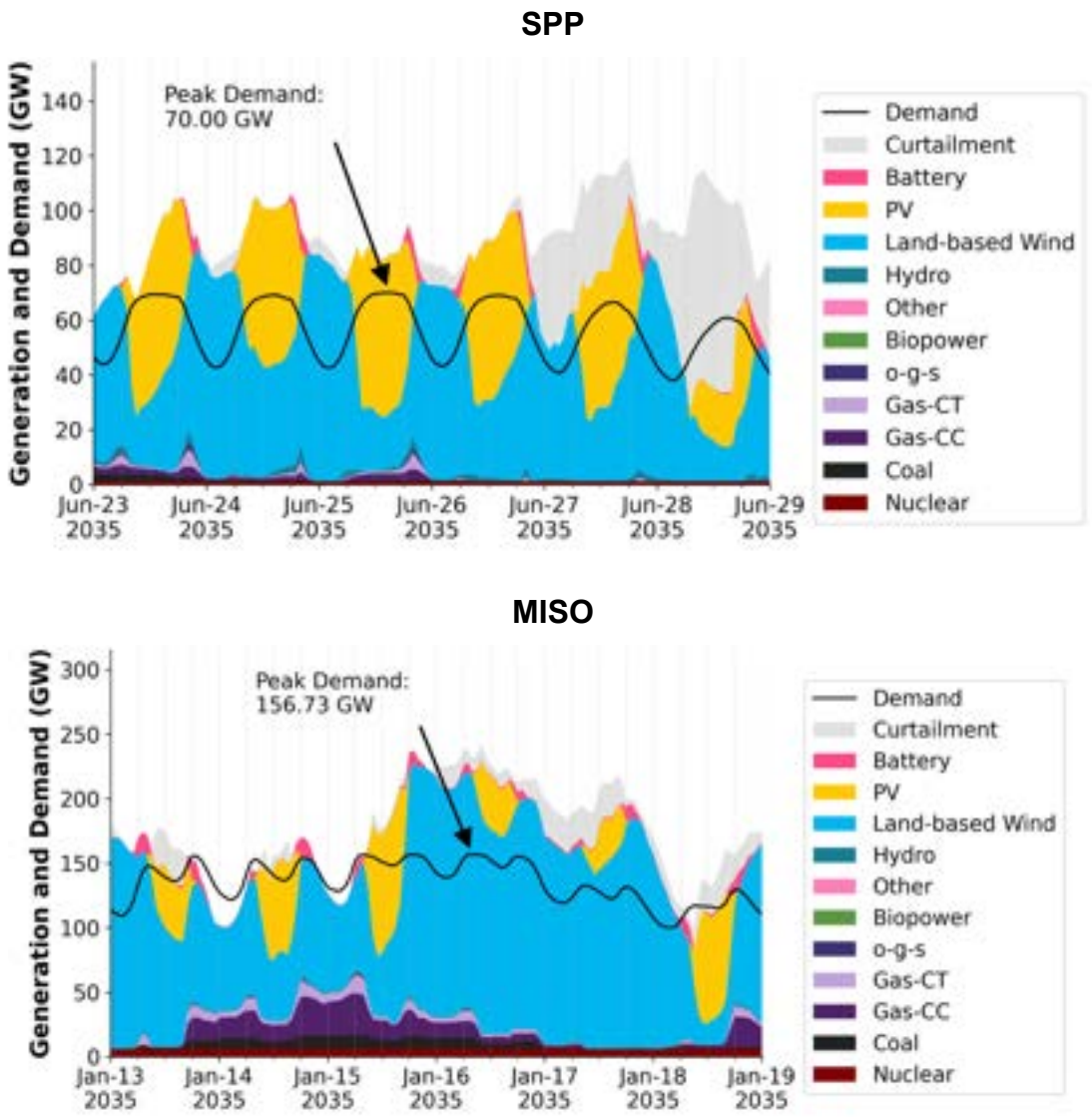



Figure 28. Dispatch stacks of peak demand for SPP (top) and MISO (bottom) for the AC scenario

Figure 29 shows the net interchange relative to native demand for the regions across the continental United States, where a positive indicates exports and a negative indicates imports. Several regions move power in one predominant direction as exports (SPP, MISO, WestConnect, ERCOT) and as imports (CAISO, PJM, NYISO) whereas others move power bidirectionally (NorthernGrid, SERTP, FRCC, ISONE). In the scenarios with more interregional transmission (AC and MT-HVDC), the relative amount of demand met by imports or the amount of power exported from a region increases, highlighting coordination between regions would be expected to increase. Across almost all regions, the AC and MT-HVDC scenarios lead to more overall energy exchange. More specifically,19% of the total energy consumed in the Limited scenario flows over interregional transmission lines whereas that number increases to 28% in the AC and 30% in the MT-HVDC scenario.

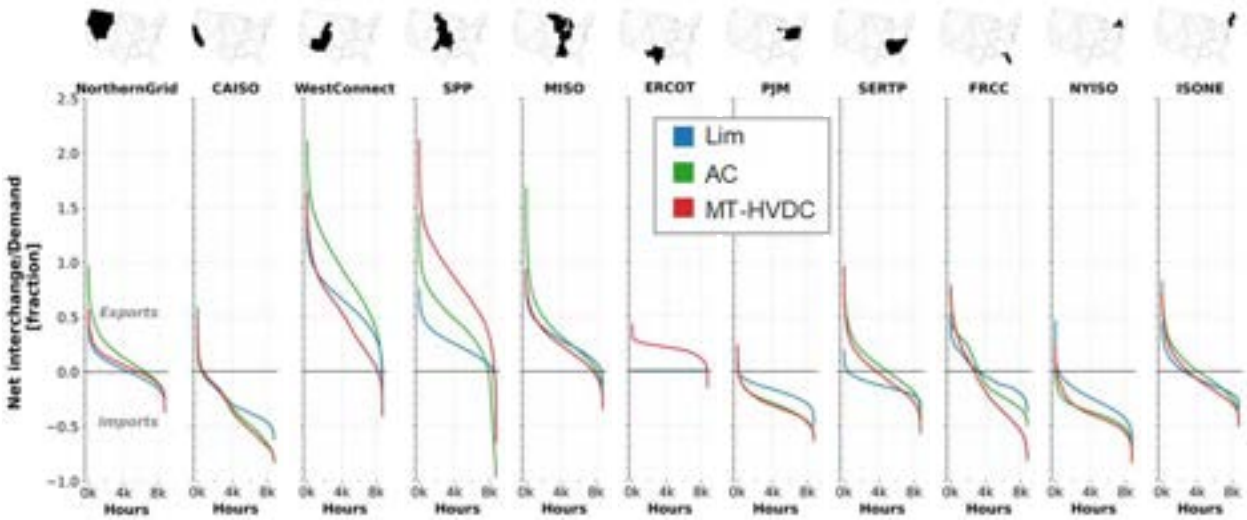



Figure 29. Ratio of Net interchange to for the 11 regions all hours of the year (2035) for Limited, AC, and MT-HVDC nodal scenarios

*Positive values indicate net exports and negative values indicate net imports. The MT-HVDC scenario refers to the nodal 2035 translation of the MT scenario, which encompasses characteristics of both HVDC scenarios from the zonal scenarios.*

# 4 Western Interconnection Results for Downstream Modeling

This section presents results derived from the earlier ReEDS scenarios; results were informed by the baseline analysis performed on the Western Interconnection.[51] The three earlier scenarios that are translated to nodal scenarios are all 90% by 2035 emission constrained, high-demand, with the Limited, AC, and MT-HVDC transmission frameworks.[52] The resulting nodal transmission expansions and production cost modeling results for the model year 2035 for the Western Interconnection are presented in this section.

The results are structured into three categories. Infrastructure changes, the results of the disaggregation, and transmission expansion are described in Section 4.1. Operational results from production cost modeling simulations of the 2035 model year follow in Section 4.2. Finally, the impact of infrastructure and operation changes are combined in an economic evaluation and analysis of the nodal scenarios in Section 4.3. In addition, this section uses regions familiar to stakeholders in the Western Interconnection. See Appendix B.2, Figure B-44 for a map of these regions.[53]

## 4.1 Translating Zonal Scenarios to Nodal Network Scenarios

This section describes the results of the resource disaggregation in the nodal models and the transmission expansion decisions made to accommodate the new resources. Details on the MT-HVDC design are provided in Appendix A.10.

### 4.1.1 Increased transmission expansion in the West via long-distance high-capacity lines could enable lower overall generation capacity investment by connecting the resources far from load centers

Though solar PV makes up the largest share of generation capacity in all three scenarios, the increased share of wind in the AC and MT-HVDC scenarios—enabled by more interregional transmission capacity—makes it possible to support the same load in the Western Interconnection with a lower level of total installed capacity.[54] Figure 30 shows the total Western Interconnection generation and storage capacity, and Figure 31 shows the resulting transmission expansion for the three scenarios.

**The Limited scenario** is characterized by significant amounts of solar and storage additions, particularly in the southwest and California. These drive a substantial amount

[51] For the baseline analysis, see Konstantinos Oikonomou et al. (2024). For details on the different assumptions used in ReEDS to create earlier and final scenarios, see Chapter 1 of this report.
[52] The MT-HVDC scenario is modeled with the Western Interconnection and the Eastern Interconnection; however, only results from the Western Interconnection footprint are included in this section. Appendix B.5 includes a map of the Eastern and Western Interconnection portfolios.
[53] Regions referenced in Section 4 are Northwest U.S. West and East (NWUS-W, NWUS-E), Basin (BASN), California North and South (CALN, CALS), Desert Southwest (DSW), and Rocky Mountain (ROCK).
[54] The economic analysis, Section 4.4, evaluates the trade-off between generation and transmission capacity.

of intraregional transmission along the southern border as well as around the Los Angeles (LA) Basin to collect the resources and connect them to load centers.

**The AC scenario,** capitalizing on the ability to build longer-distance interregional AC transmission, incorporates more high-quality wind resources from regions on the eastern part of the Western Interconnection (ROCK, BASN, DSW) compared to the Limited scenario. The transmission expansion helps connect the new wind resources to load centers in Colorado, Arizona, and the coast. The transmission expansion connects the remote wind areas to the 500-kV backbone but also reinforces the system and expands interregional connections to allow access to these load centers. In contrast, there is significantly less solar PV and storage capacity, particularly in the southwest in the AC scenario compared to the Limited scenario. Accordingly, there is less intraregional transmission, most notably along the southern border.

**The MT-HVDC scenario** is substantially different from the Limited and AC scenarios because four HVDC converters with 20 GW of capacity between the western and eastern interconnections are added. This enables a large amount of energy exchange across the seams, with imports from the SPP region being predominantly wind. The wind capacity in the MT-HVDC scenario is distributed similarly to the AC scenario at higher-quality locations along the east, supported by an HVDC backbone along the eastern part of the interconnection with further connections toward the coastal load centers. The total wind capacity, however, is only 9 GW more than the Limited scenario given the ability to import additional high-quality resources across the seams.[55] Like the AC scenario, the MT-HVDC scenario has less solar and storage installed than the Limited scenario and therefore less intraregional transmission expansion along the southern border.

Transmission expansion decisions are categorized into three groups that are outlined further in the following paragraphs.

The first is high-voltage transmission lines that can span large, potentially interregional, distances but whose primary role is to collect VRE injections from remote locations and give them a path to the larger bulk system. For example, this type of expansion characterizes much of the built transmission in Montana or New Mexico in all scenarios.

A second type of expansion reinforces congested corridors in the existing bulk system or expands the bulk system via new corridors. The difference between this category and the first is the lines in this category are primarily intended to connect regions. Though not a requirement, flow on these lines is more likely bidirectional. The 500-kV expansion across northern Arizona is one such example, as well as the Garrison to Midpoint lines in the Limited and AC scenarios. Perhaps most prominently, all the HVDC expansion in the MT-HVDC scenario is in this category.

[55] In fact, the difference between the installed wind capacity in the AC and MT-HVDC scenarios is very close to the roughly 20 GW of HVDC capacity across the seams.

Finally, a third type of expansion focuses on intraregional reinforcement and access to load. The expansion around the LA or Denver load pockets are examples in all the scenarios.

Appendix B.5 provides region-specific descriptions of the rationale for the expansion decisions.

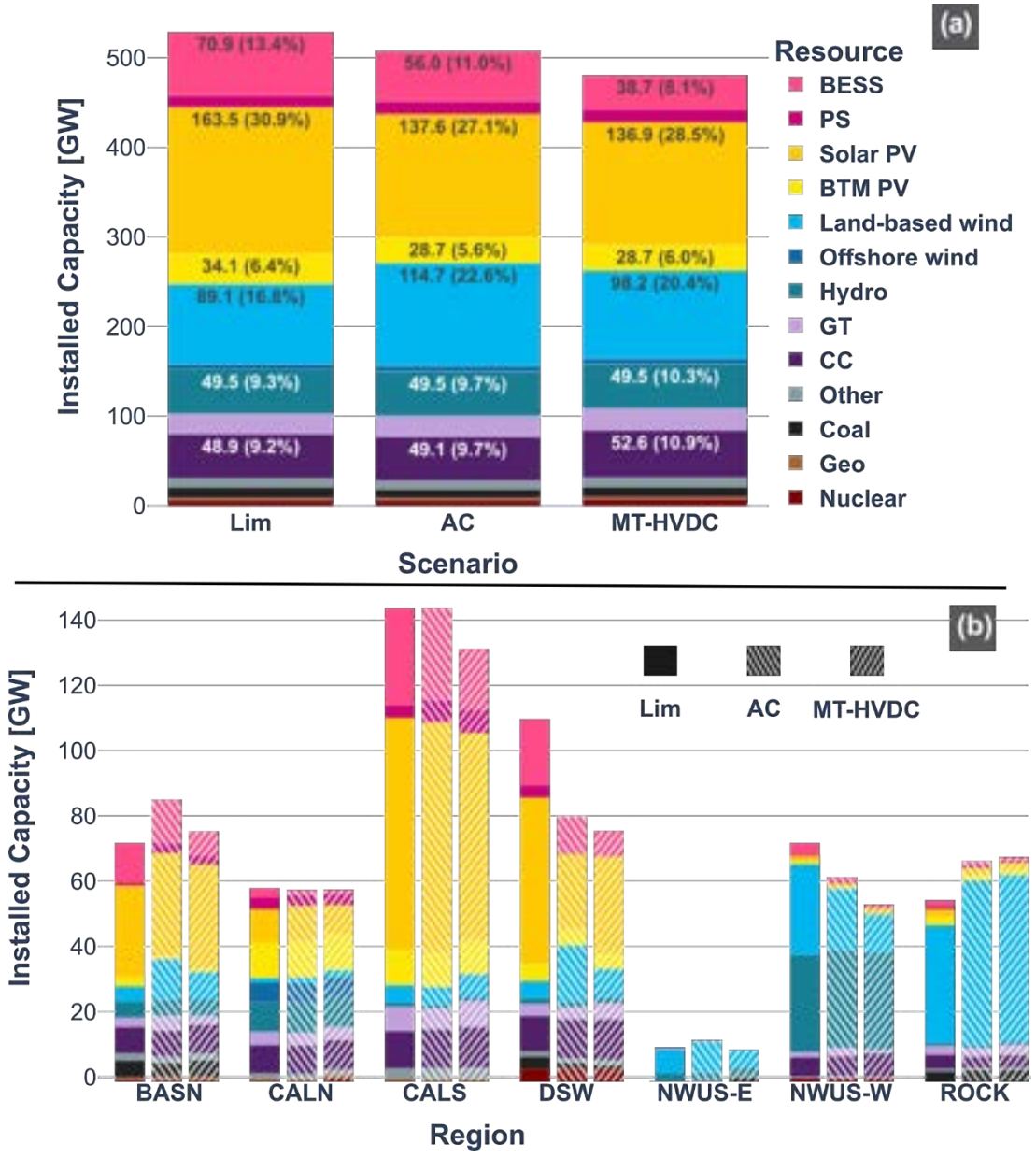



Figure 30. Net installed capacity after disaggregation: (a) Western Interconnection-wide; (b) by subregion

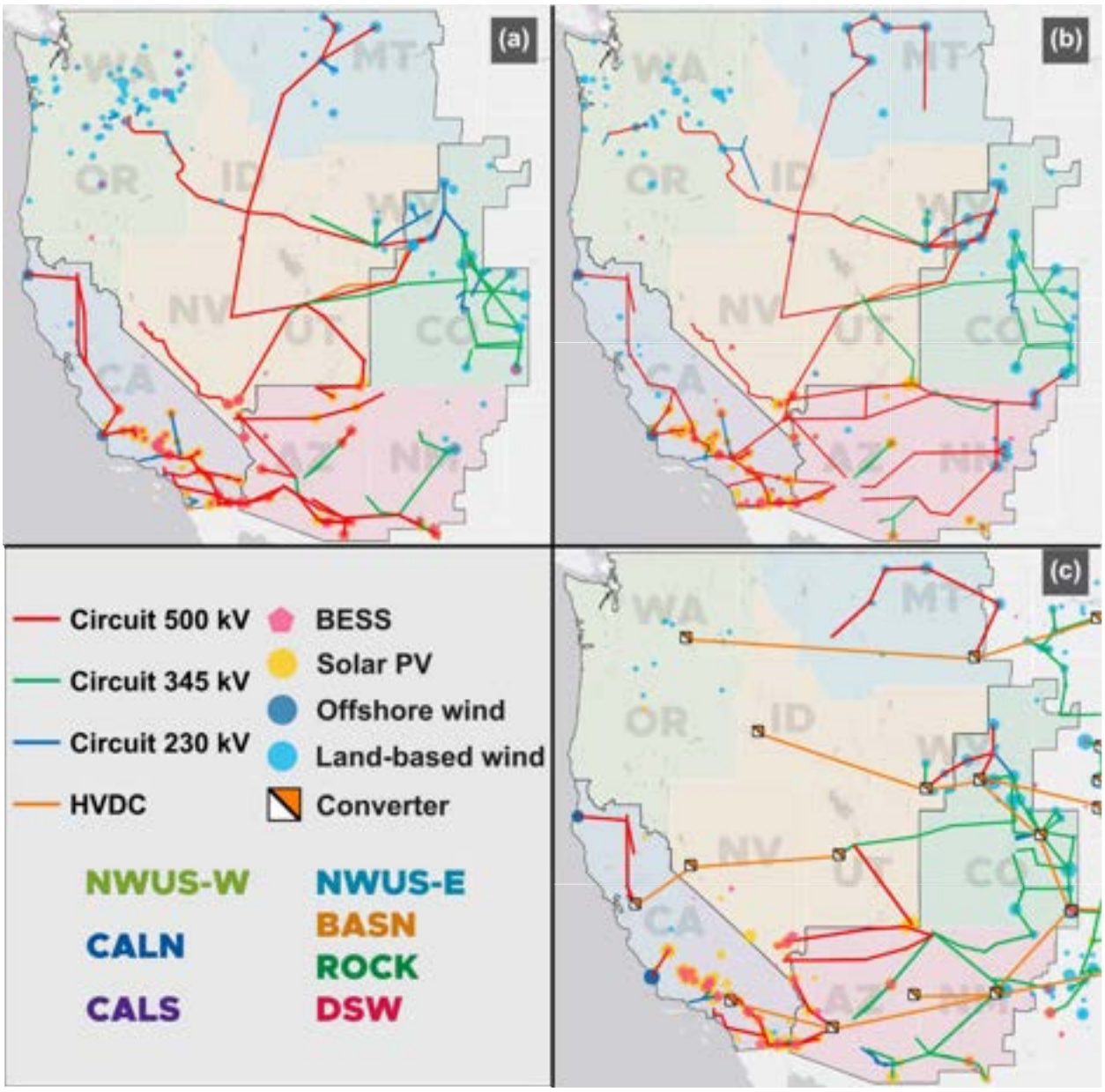



Figure 31. Transmission expansion results on the Western Interconnection footprint

*Nodal transmission expansion is shown for the earlier rounds ReEDS scenarios with (a) Limited, (b) AC, and (c) MT-HVDC results shown. Expansion results for the full MT-HVDC scenario are provided in Appendix B.5 (for CONUS).*

## 4.2 Operations of Highly Decarbonized Power Systems

This section presents operational results from production cost simulations on the three translated scenarios. These results serve two distinct purposes:

- Validation: Demonstrate an operationally viable realization of the capacity expansion results that can be used to seed further downstream models (see Chapter 4 for power flow and Chapter 5 for stress analysis).
- Present analysis of operation under ~90% renewable penetration and the role of transmission and generation technologies in the operation of such futures.

Appendices A.8 and A.9 provide more detail on the simulation process and the earlier ReEDS scenario translations.

### 4.2.1 Operational flexibility is achieved by a changing generation mix that correlates with the amount of interregional transmission capacity

For the Western Interconnection scenarios, as interregional transmission increases, the share of wind in the total energy mix increases from 270 TWh (21%) in the Limited scenario to 346 TWh (28%) in the AC scenario and 439 TWh (36%) in the MT-HVDC scenario. The reliance on gas generation (gas turbine [GT] and combined cycle [CC]) makes up a smaller share as interregional transmission increases from 11% in the Limited to 10% in the AC and 5% in the MT-HVDC scenario. Figure 32 shows the annual generation in the entire Western Interconnection and by region. Interregional imports and exports have a large impact on certain regions in the AC and MT-HVDC scenarios. In particular, the HVDC connections (shown as DC imports in Figure 32) to the Eastern Interconnection in the MT-HVDC scenario have a large impact on flows around the entire interconnection.

Storage charge and discharge patterns highlight the different sources of flexibility between the scenarios. Figure 33 shows the average weekday dispatch in the third quarter of the year, which in the Western Interconnection contains the peak load period. Storage plays a significant role in meeting the evening ramp and peak, but it is more pronounced in the Limited and AC scenarios. In the MT-HVDC scenario, the lower storage contribution is compensated by more wind as well as imports through the HVDC links that show a similar pattern to storage. In the AC and MT-HVDC scenarios, storage discharge reduces significantly overnight (hours 0–5) compared to the higher levels in the Limited scenario. In the AC scenario, the nighttime generation is picked up by more wind whereas in the MT-HVDC scenario the HVDC imports—in addition to the higher wind generation—help drive down the share of gas generation dispatched overnight. Figure 34 shows the average weekday storage dispatch over the whole year, further emphasizing the wider charge and discharge range as well as overnight discharge level in the Limited scenario.

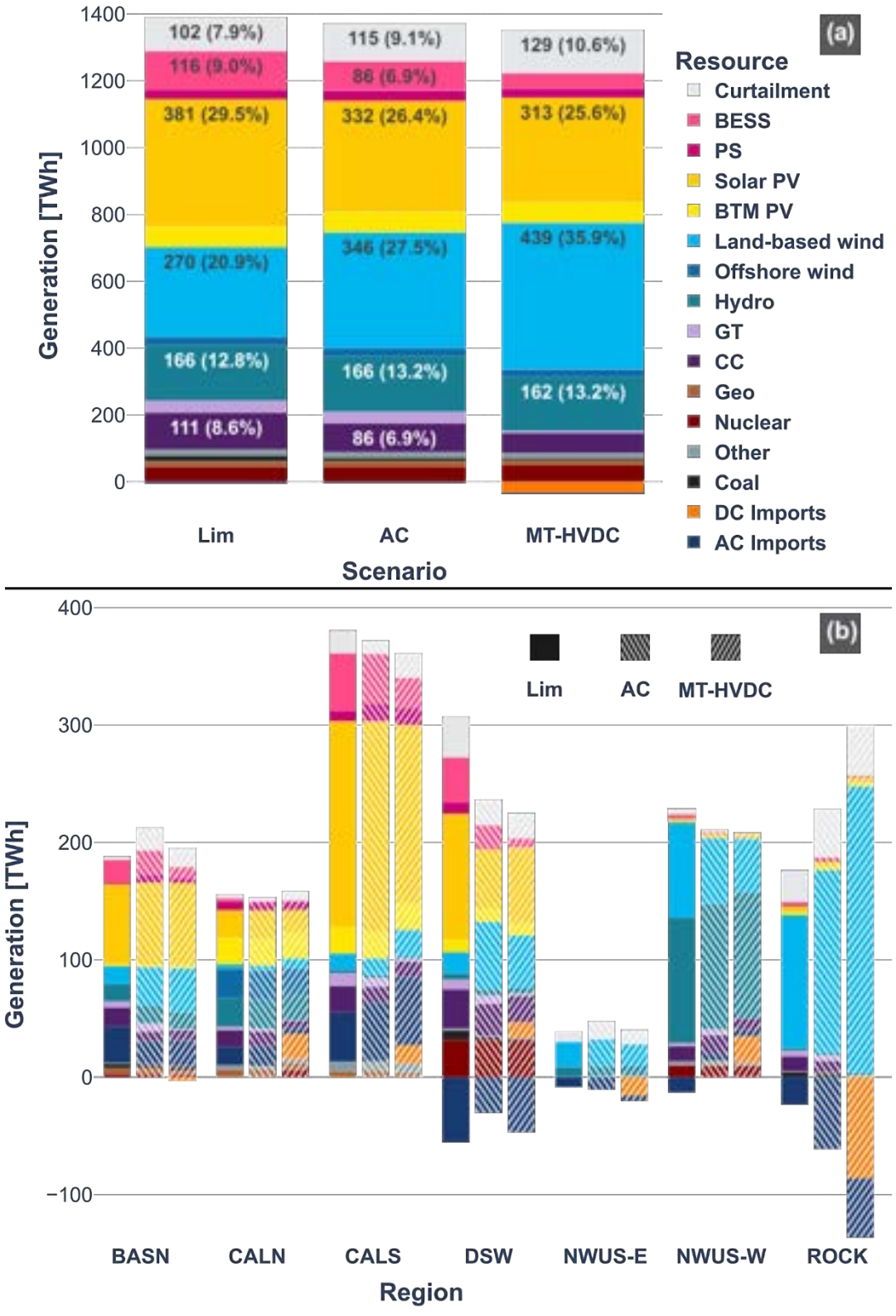



Figure 32. Annual generation mix comparison for (a) Western Interconnection and (b) by subregion

*Percentages are with respect to total generation within the footprint, in other words, neglecting the DC and AC imports, and curtailment values. Storage values are for generation mode only.*

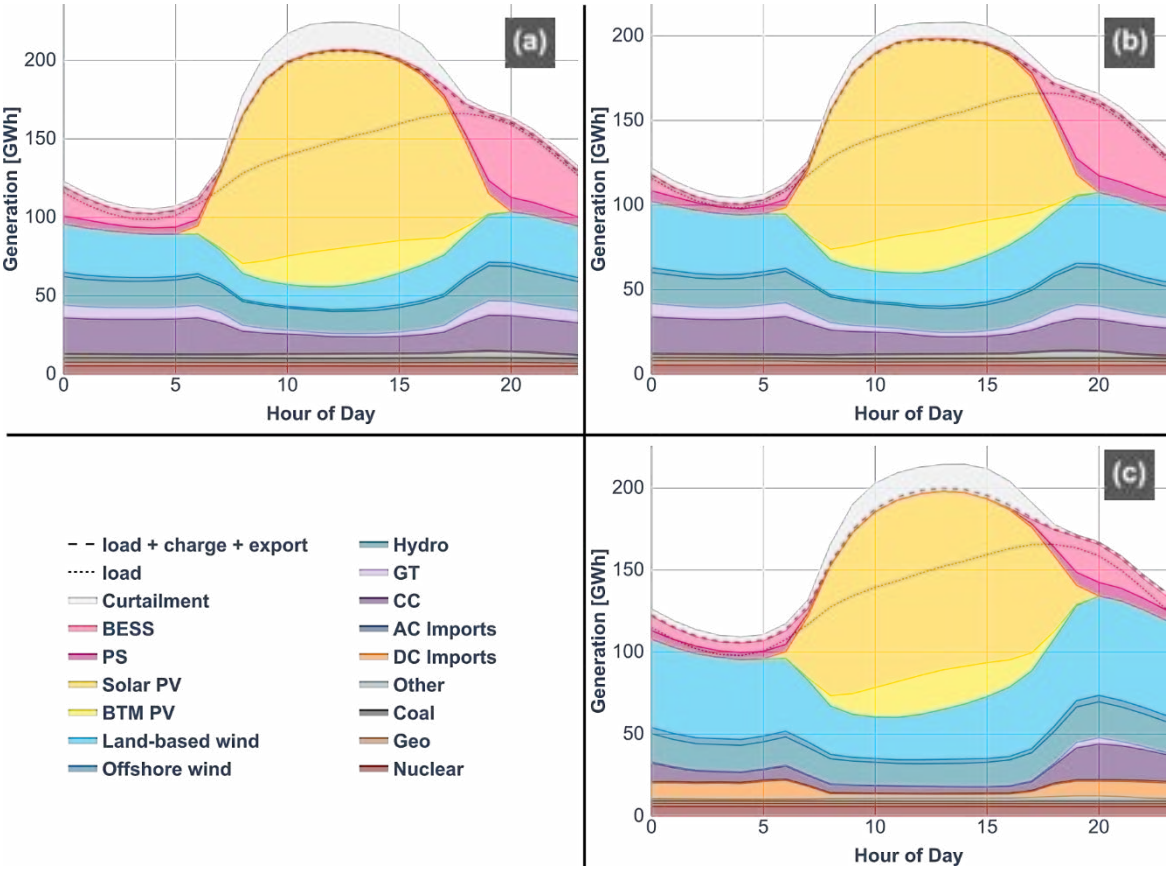



Figure 33. Average weekday in the third quarter of the model year for (a) Limited, (b) AC, and (c) MT-HVDC

*DC imports refer to energy imported across the seam from the Eastern Interconnection. Storage values are for generation mode only.*

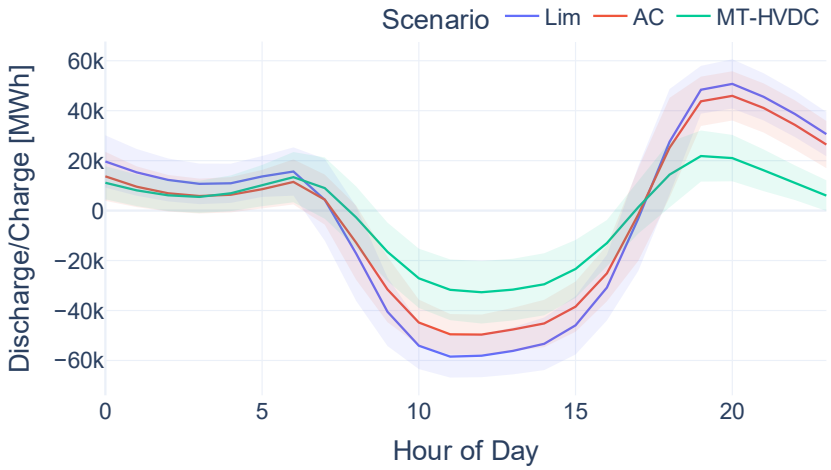



Figure 34. Average weekday storage dispatch for the Western Interconnection

*Lines are the average value; shaded areas are ±1 standard deviation around the mean.*

### 4.2.2 Transmission paths connecting diverse VRE resources will experience more bidirectional flow and diurnal patterns

Increased interregional transmission and its correlation with more geographically dispersed VRE resources lead to more pronounced diurnal patterns on transmission paths, largely driven by solar PV generation, as well as changes in the dominant directionality of flow.

The upgraded transmission paths for the additional wind resources in New Mexico, Colorado, and Wyoming toward the California load centers passes through southern Nevada and Arizona in the AC and MT-HVDC scenarios. Figure 35 shows the flows on the interfaces between CALS and BASN (southern Nevada) as well as DSW (Arizona).[56] During the nighttime hours, the magnitude of the import flows to California increases on average by around 5 GW in both the AC and MT-HVDC scenarios compared to the Limited scenario. During the daytime hours, the significant solar resources in CALS reduce the flow on the interfaces, resulting in a diurnal pattern that reflects the solar PV output.

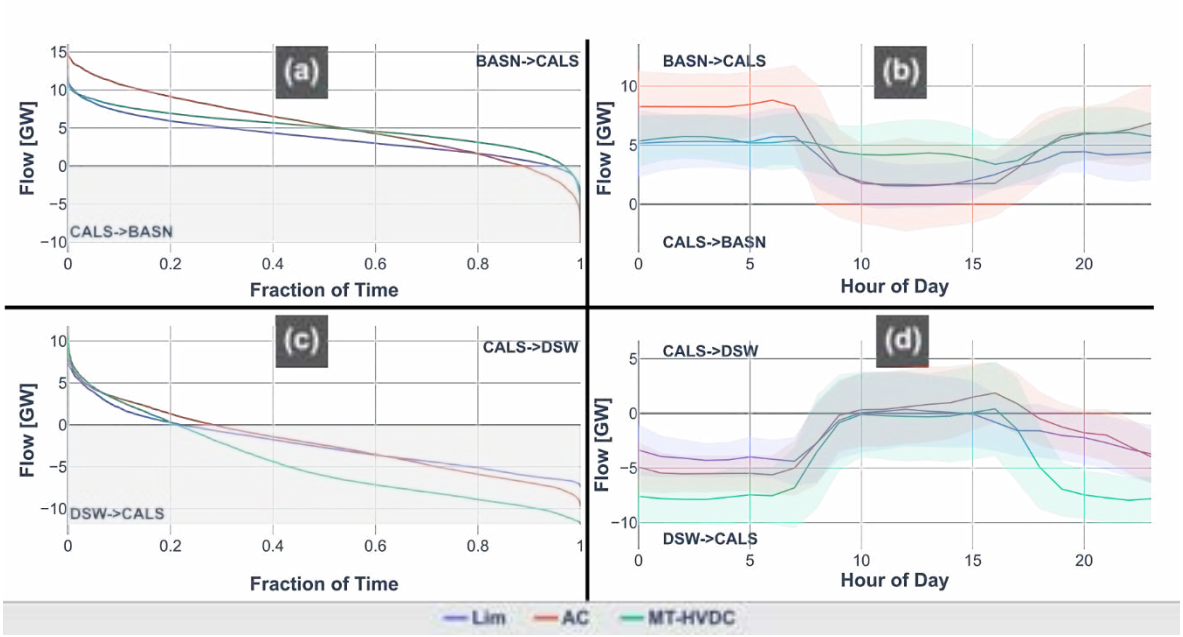



Figure 35. Flows between Basin and Southern California and between Desert Southwest and Southern California

*Panels (a) and (c) are flow duration curves. Panels (b) and (d) show average weekday plots with ±1 standard deviation shaded.*

The interface between the Basin region (BASN) and the Pacific Northwest (NWUS-W) in Figure 36 is an example of how interregional transmission impacts the dominant flow direction between regions. In this case, the transmission capacity between the two regions in the three scenarios is similar, but the impact of expansion elsewhere in the

[56] Note in the AC scenario a significant portion of the new 500-kV transmission passes through southern Nevada whereas in the MT-HVDC scenario, the HVDC corridor connects Arizona (DSW) to southern California.

Western Interconnection impacts how that transmission capacity is used. Central to the shift in usage pattern is the reduction of wind resources in NWUS-W (cf. Figure 30) in favor of eastern regions of the Western Interconnection, which is enabled by more interregional expansion. Figure 36 shows how NWUS-W shifts from exporting power to BASN for more than 50% of the year in the Limited scenario to importing power for 60% (MT-HVDC) and 75% (AC) of the year. This underscores the shift in total yearly energy exchange for NWUS-W, seen in Figure 32, from 13 TWh *exporting* to 7 TWh *importing* and 28 TWh *importing* in the Limited, AC, and MT-HVDC scenarios, respectively.

In the MT-HVDC scenario, there is an HVDC path to the Pacific Northwest, which brings wind from Montana and North Dakota and acts as an alternative wind import option for NWUS-W. There is also an MT-HVDC link from BASN to the east that offers an alternative export destination to NWUS-W. As a result, the BASN-NWUS-W interface has a flatter average flow but a wider standard deviation in Figure 36, driven by the increased variations in available flow patterns.

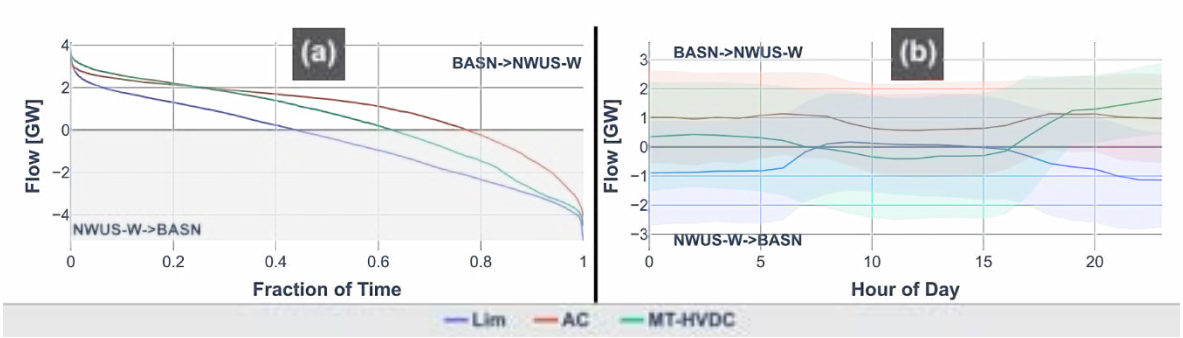



Figure 36. Interface between Basin and Pacific Northwest

*Panel (a) flow duration curve and panel (b) average weekday shape with ±1 standard deviation shaded.*

### 4.2.3 HVDC links between the Western and Eastern Interconnections are highly used and exhibit geographically dependent bidirectional flows

The 20 GW of HVDC capacity added between the Western and Eastern Interconnections in the MT-HVDC scenario is used substantially, as illustrated in the flow duration curves of Figure 37, where flat portions represent operation at the limit. All four HVDC links connecting the Western and Eastern Interconnections in the MT-HVDC scenario move power in both directions—importing to the Western Interconnection and exporting from it. The degree of bidirectionality varies geographically: larger in the north and south and lesser in the middle between ROCK and SPP.

The northernmost connection between Montana and North Dakota exhibits a light diurnal pattern. At times, power flows west-to-east during the day when there is much solar PV available in the West and the link offers an alternative sink for wind. During the evening and nighttime, the flow is predominantly east-to-west as also seen in the storage-like behavior of HVDC for the West in Section 4.2.1. The southernmost seam, between DSW and SPP-South, exhibits a strong diurnal pattern and is evenly split between daily west-east and nightly east-west flows.

The ROCK region, containing Colorado and parts of Wyoming, has two connections to the Eastern Interconnection via SPP-North and SPP-South. In both, power flows predominantly west-to-east, although east-to-west flows make up around 10% of the time. This is likely because of ROCK's weaker connection to the rest of the Western Interconnection, making it easier to send power east versus west.[57]

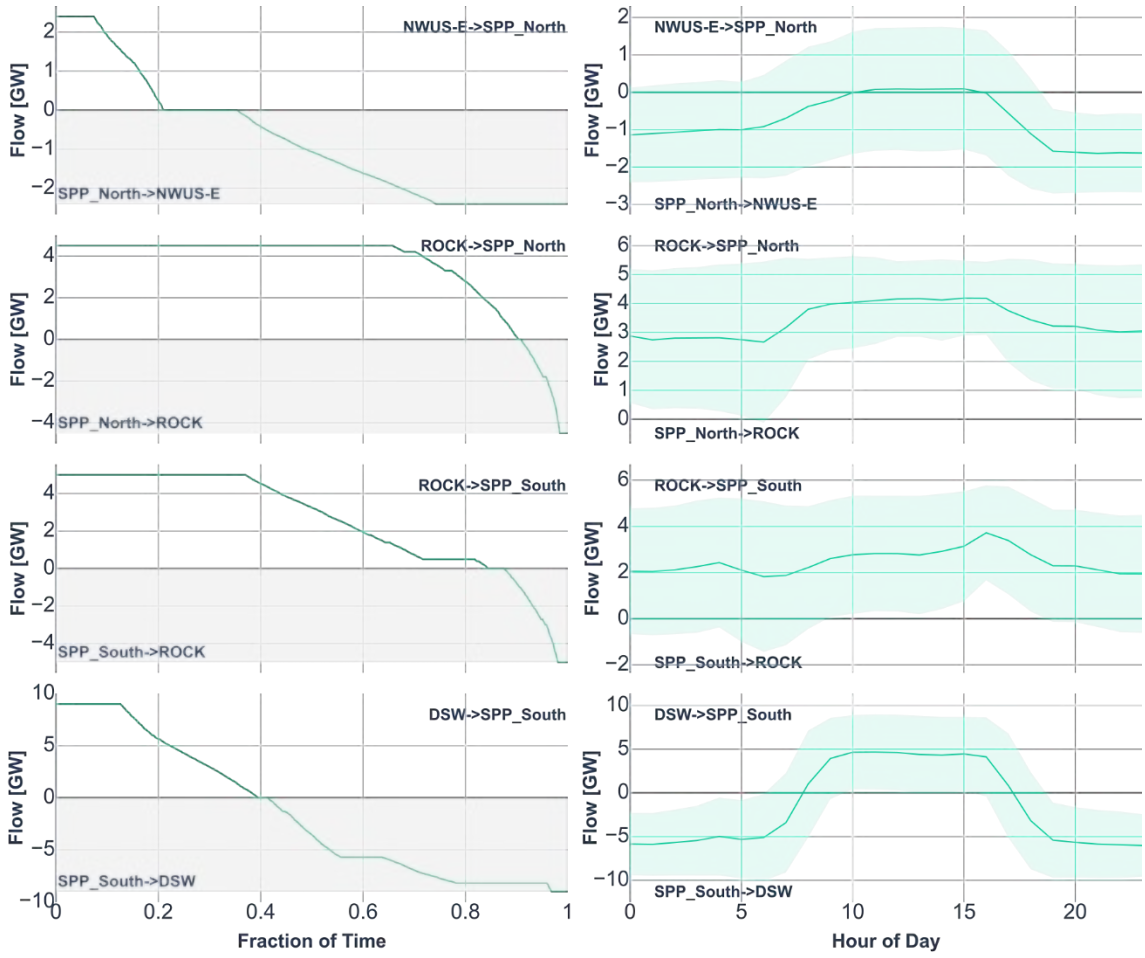



Figure 37. Flow duration curve (left) and average weekday across four Western-Eastern Interconnection seam corridors

## 4.3 Economic Analysis Indicates Benefits From More Interregional Transmission in the Considered Scenarios

This section highlights the avoided costs and other economic benefits estimated from the earlier nodal scenarios modeled. The metrics presented are the avoided costs and benefits to the Western Interconnection only. The results compare the three earlier nodal scenarios modeled—Limited, AC, and MT-HVDC—and the results may not

[57] The MT-HVDC buildout from the plains eastward is much more extensive than the buildout in the west. Therefore, issues around weak connections on the Eastern Interconnection side are more robustly addressed. Details of the full HVDC expansion are available in Appendix B.5.

generalize to other transmission scenarios or portfolios. Grid planners will need to conduct comprehensive nodal economic analysis as potential transmission projects are planned and implemented. Because these results use earlier scenario input assumptions, the estimates differ from the zonal economic analysis presented in Chapter 2 of the NTP Study that uses final scenario input assumptions. The economic results demonstrate interregional transmission could provide cost savings to the grid.

### 4.3.1 Increased transmission capital cost expenditures in the studied interregional scenarios coincide with lower generation capital costs

The transmission costs for the Limited scenario total $46.2 billion including a 17.5% adder for an AFUDC. The added transmission for the AC scenario totaled $55.1 billion. The transmission costs for the MT-HVDC are $80.0 billion for transmission lines and converter stations including the AFUDC. The study team estimated costs for each set of transmission lines using the WECC Calculator (Black & Veatch 2019). Table 8, Table 9, and Table 10 include the total number of lines, total line miles, average cost per mile, and the total cost for each case.

Table 8. Transmission Capital Cost for the Limited Scenario

| | Number of Lines | Total Mileage | Costs ($B) |
|---|---|---|---|
| Right-of-Way Cost | 220 | 10,373 | 0.2 |
| Transmission Line Cost | 220 | 14,905 | 39.1 |
| Total Cost | | | 46.2 |

Table 9. Transmission Capital Cost for AC Scenario

| | Number of Lines | Total Mileage | Costs ($B) |
|---|---|---|---|
| Right-of-Way Cost | 232 | 11,971 | 0.2 |
| Transmission Line Cost | 232 | 18,447 | 46.7 |
| Total Cost | | | 55.1 |

Table 10. Transmission Capital Cost for the MT-HVDC Scenario

| | Number of Lines | Total Mileage | Costs ($B) |
|---|---|---|---|
| Right-of-Way Cost | 225 | 15,164 | 0.2 |
| Transmission Line Cost | 225 | 24,594 | 53.6 |
| Converter Station Costs | | | 14.5 |
| Total Cost | | | 80.0 |

Table 11, Table 12, and Table 13 list the costs by voltage class to show the differences across the scenarios considered. The Limited scenario contains the highest 230-kV costs because of its higher reliance on intraregional expansion. The 500-kV costs dominate the AC scenario as the primary mode of interregional expansion used. Finally, HVDC transmission drives the MT-HVDC scenario costs.

Table 11. Cost by Mileage and Voltage Class for the Limited Scenario

| kV | Circuit Count | Circuit Miles | Right-of-Way Cost ($M) | Transmission Lines ($B) | Cost/Mile ($M) | Total Cost ($B) |
|---|---|---|---|---|---|---|
| 230 AC | 50 | 1,731 | 20.0 | 2.5 | 1.7 | 3.0 |
| 345 AC | 68 | 3,585 | 22.1 | 6.9 | 2.3 | 8.1 |
| 500 AC | 185 | 9,590 | 128.8 | 29.8 | 3.7 | 35.1 |

Table 12. Cost by Mileage and Voltage Class for the AC Scenario

| kV | Circuit Count | Circuit Miles | Right-of-Way Cost ($M) | Transmission Lines ($B) | Cost/Mile ($M) | Total Cost ($B) |
|---|---|---|---|---|---|---|
| 230 AC | 29 | 972 | 20.0 | 1.5 | 2.1 | 1.7 |
| 345 AC | 54 | 3,844 | 24.7 | 7.4 | 2.6 | 8.7 |
| 500 AC | 149 | 13,591 | 137.5 | 37.8 | 3.9 | 44.6 |

Table 13. Cost by Mileage and Voltage Class for the MT-HVDC Scenario

| kV | Circuit Count | Circuit Miles | Right-of-Way Cost ($M) | Transmission Lines ($B) | Cost/Mile ($M) | Total Cost ($B) |
|---|---|---|---|---|---|---|
| 230 AC | 30 | 725 | 16.5 | 1.0 | 1.7 | 1.2 |
| 345 AC | 92 | 7,667 | 33.2 | 13.3 | 2.0 | 15.7 |
| 500 AC | 88 | 8,526 | 67.1 | 23.8 | 3.3 | 28.0 |
| 500 HVDC | 15 | 7,676 | 48.7 | 29.7* | 4.6 | 35.0 |

**Includes converter stations*

ReEDS output for 2022–2034 provides the basis for the generation capital costs.[58] The values obtained from ReEDS were in 2004$ and escalated to 2018$ using the Consumer Price Index. The total generation capital costs are $211.3 billion for the Limited scenario. The AC and MT-HVDC costs decrease to $163.0 billion and $151.8 billion, respectively, which is $48 billion and $59 billion less than the Limited scenario.

### 4.3.2 Operating costs decrease with increased interregional transmission, resulting in greater net annualized benefits

Table 14 shows the overall annual production avoided costs. The annual operation costs for the Limited, AC, and MT-HVDC scenarios are $9.6 billion, $7.6 billion, and $5.5 billion, respectively. Thus, the AC scenario has avoided costs of $2.0 billion annually whereas the MT-HVDC has avoided costs of $4.1 billion. The reduction in fossil fuel use in the AC and MT-HVDC scenarios drives the majority of these avoided costs. In addition to the reduction in fossil fuel usage, there is a change in the renewable resource mix. The Limited scenario relies more on solar and storage, which results in larger ITC payments to solar generators compared to the other scenarios. Annualized ITC payments to solar are $2.7 billion for the Limited scenario, $2.3 billion for the AC scenario, and $2.0 billion for the MT-HVDC scenario. The reduction in solar is offset with an increase in wind generation in the AC and MT-HVDC scenarios, largely in the eastern regions of the Western Interconnection. The PTC payments are $7.8

[58] Generation costs are not split out by resource type.

billion in the Limited scenario, $9.9 billion in the AC scenario, and $12 billion in the MT-HVDC scenario.

Table 14. Summary of Annual Savings Compared to the Limited Case

| | AC | MT-HVDC |
|---|---|---|
| Annual fuel and other operating costs | $2.0 Billion | $4.1 Billion |
| Annual subsidy to wind (PTC) | -$2.1 Billion | -$4.2 Billion |
| Annualized subsidy to solar + storage (ITC) | $0.4 Billion | $0.7 Billion |

The overall net avoided costs are estimated by adding the savings from transmission capital costs, generation capital costs, and operational costs. The study team annualized these avoided costs to enable their addition because operational avoided costs are expected to accrue annually whereas the capital costs are paid once and provide infrastructure with a lifetime of many years. The study team used annualized avoided costs instead of the net present value of avoided costs because the operating costs are estimated from simulations of a single year (2035). The formula used to annualize the avoided costs is as follows (Becker 2022):

$$Annualized\ Cost = C \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where *n* is the lifetime of the investment, *r* is the discount rate, and *C* is the cost being annualized. The study team assumed the lifetime of transmission capital is 40 years and the lifetime of generation capital is 20 years. The results are estimated using two discount rates—3% and 5%—to show the range of avoided costs across different discount rate assumptions. Table 15 shows the total net annualized avoided costs of the AC scenario and MT-HVDC scenario and provides net annualized avoided costs above the Limited scenario across the range of discount rates. The MT-HVDC scenario delivers greater net annualized avoided costs than the AC scenario for each discount rate used.

Table 15. Total Annualized Net Avoided Costs of the AC and MT-HVDC Scenarios Compared to the Limited Scenario

| | AC | | MT-HVDC | |
|---|---|---|---|---|
| | **3% ($B)** | **5% ($B)** | **3% ($B)** | **5% ($B)** |
| Annualized Value: Transmission and generation capital, and operating costs | 5.0 | 5.5 | **6.6** | **6.9** |
| Annualized Value: Generation capital and operating costs (transmission capital excluded) | 5.4 | 6.0 | 8.1 | 8.9 |

The study team used the production cost modeling outputs to disaggregate the estimated annual operating avoided costs to estimate benefits accruing to different stakeholders that are part of the grid. The methodology and formulas used in this section are described in more detail in Section 2.6. Note the benefits estimated and identified in this section include direct economic benefits from the electricity system and do not include other benefits such as health benefits from lowered emissions.

The difference in annual profits (revenues-costs) between the two scenarios defines generator benefits. Note capital costs are not included as part of this annual benefit disaggregation. Revenues for each generator are estimated as their LCOE × generation dispatched (TWh); these revenues are shown in Table 16. This calculation assumes LCOE is the price each generator receives under a PPA with a negotiated price at their LCOE.[59] LCOE can be interpreted as the minimum average price a generator requires to attract investment funding, so these results can be considered a lower bound of the benefits to generators. In the AC and MT-HVDC scenarios, the generators function with lower operating costs and lower revenue from power than in the Limited scenario. The reduction in natural gas and other fossil fuel generation drives the lower operating costs. The increase in wind generation, with a lower LCOE and thus less revenue per MWh of power, reduces generator revenues in both the AC and MT-HVDC scenarios. However, wind generators also receive PTC payments and, after including PTC payments to wind generators, the benefits to generators are $1.7 billion higher than in the AC scenario and $0.4 billion lower in the MT-HVDC compared with the Limited scenario (Table 17).

[59] Several studies identify marginal-cost pricing in a highly decarbonized electricity system results in prices that do not provide adequate revenue for generators to recover their costs (Milligan et al. 2017; Blazquez et al. 2018; Pena et al. 2022).

Table 16. Detailed Generation and Revenue by Generator Type

| | | Limited | | AC | | MT-HVDC | |
|---|---|---|---|---|---|---|---|
| Generator Type | Price Used (LCOE) ($/MWh) | Quantity (TWh) | Revenue ($B) | Quantity (TWh) | Revenue ($B) | Quantity (TWh) | Revenue ($B) |
| Nuclear | 90.54 | 45 | 4.0 | 45 | 4.0 | 51 | 4.6 |
| Geothermal | 57.75 | 17 | 1.0 | 18 | 1.0 | 14 | 0.8 |
| Coal | 68.00 | 16 | 1.1 | 10 | 0.6 | 6 | 0.4 |
| Wind: Land-based | 22.13 | 270 | 6.0 | 346 | 7.7 | 439 | 9.7 |
| Wind: Offshore | 56.87 | 25 | 1.4 | 25 | 1.4 | 23 | 1.3 |
| Solar PV | 25.43 | 442 | 11 | 394 | 9 | 374 | 9 |
| Hydro | 95.88 | 166 | 16 | 166 | 16 | 162 | 16 |
| Natural Gas (CC)[60] | 62.00 | 111 | 6.9 | 86 | 5.4 | 60 | 3.7 |
| Natural Gas (peaker) | 157.00 | 35 | 5.6 | 34 | 5.4 | 6 | 0.9 |
| Storage | 29.32 | 144 | 4.2 | 118 | 3.5 | 74 | 2.2 |
| Other | 68.00 | 18 | 1.2 | 17 | 1.2 | 15 | 1.1 |
| | | | | | | | |
| Total | | **1,289** | **57.9** | **1,258** | **55.5** | **1,223** | **49.2** |

[60] LCOE is computed using the energy generation over the lifetime of the asset. This is fairly consistent year-to-year for wind, solar, and baseload generators. For generators that are dispatchable, such as natural gas, the capacity factor can vary more widely over time. The average LCOE estimates from Lazard (2023) use a capacity factor of 57.5% for gas CC (operating) and 12.5% for gas peaking. The average capacity factors from the NTP scenarios for 2035 only (coming from the PCM simulation) are 26%, 20%, and 13% for CC and 18%, 17%, and 3% for peakers for Limited, AC, and MT-HVDC, respectively. If these capacity factors were assumed to hold for the lifetime of the generators, these gas plants would need larger revenue to achieve full cost recovery. These larger payments would increase generator benefits (Table 17, Line 2) by $2B in the AC and $9.1B in the MT-HVDC scenario compared to the Limited case and reduce power purchaser benefits (Table 17, Line 6) by an equal amount. Hence, the total benefits would be unaffected by this modeling change. Furthermore, the capacity factors are likely to be different from their simulated 2035 values over the lifetime of the assets. Average lifetime capacity factors would likely be higher than the 2035 snapshot because most of the fleet are not new builds and operating during years with lower renewable penetration.

The revenue to transmission owners is defined as the annual revenue requirements for the transmission capital (Short, Packey, and Holt 1995).[61] The annual revenue requirements are the minimum annual payments required to attract investment funding and should be considered a lower bound on the transmission owners' benefits. The AC and MT-HVDC scenarios provide transmission owners $0.5 billion and $2.0 billion greater revenue, respectively, than the Limited scenario. The AC and MT-HVDC scenarios require more investment in interregional transmission and thus require higher corresponding revenue requirements to the transmission owners to justify the investment.

The benefit to power purchasers is defined as the reduction in payments across the scenarios considered. The production cost model assumes load demand is equal across the scenarios considered, so the quantity and quality of power purchased is equal across the three scenarios. The benefit to power purchasers is the reduction in cost required to obtain the power. Power purchaser cost is the sum of the generator revenue and transmission owner revenue. In the AC and MT-HVDC cases, payments to generators decrease whereas payments to transmission owners increase. In sum, the power purchasers add a benefit of $1.9 billion and $6.7 billion annually under the AC and MT-HVDC scenarios, respectively, compared to the Limited scenario.

The final stakeholder considered is the taxpayers. The wind generators receive PTC payments from taxpayers. The taxpayers' benefit is defined as the avoided cost of tax payments. The negative benefits shown are the result of increased tax costs. The study team assumed taxes are collected when the PTC payments are made and do not formally model a tax system where taxes may be collected at a different time than when the subsidies are distributed. The PTC payments increase by $2.1 billion and $4.2 billion in the AC and MT-HVDC scenarios, respectively, compared to the Limited scenario, so the taxpayers' benefits are -$2.1 billion and -$4.2 billion for the AC and MT-HVDC scenarios.

Overall, these results show, in general, the benefits are distributed among the different stakeholders. The generators experience a negative benefit in the MT-HVDC scenario compared to the Limited scenario. However, renewable generation supplants substantial fossil fuel generation and thus requires less remuneration. Though the taxpayers earn a negative benefit in this disaggregation, they are broadly the same collective of end consumers that will have the total benefits passed on to them through the ratemaking process.

[61] Annual revenue requirement can be computed using the formula $ARR = I \times r(1+r)^n/((1+r)^n - 1)$ where *I* is the initial capital investment, *r* is the discount rate, and *n* is the number of annual payments expected. The values shown use r = 5% and n = 40 years.

Table 17. Disaggregation of Annual Benefits According to Stakeholders

| Stakeholder | Component | Limited ($B) | AC ($B) | | MT-HVDC ($B) | |
|---|---|---|---|---|---|---|
| | | Scenario | Scenario | Benefit* | Scenario | Benefit* |
| Generators | 1. Gen cost | 9.6 | 7.6 | -2.0 | 5.5 | -4.1 |
| | 2. Gen revenue from power | 57.9 | 55.5 | -2.4 | 49.2 | -8.7 |
| | 3. Gen revenue from PTC | 7.8 | 9.9 | 2.1 | 12 | 4.2 |
| | 4. Total gen benefit (2+3-1) | 56.1 | 57.8 | 1.7 | 55.7 | -0.4 |
| | | | | | | |
| Transmission Owners | 5. Transmission owner revenue | 2.7 | 3.2 | 0.5 | 4.7 | 2.0 |
| | | | | | | |
| Power Purchasers | 6. Payment to generators for power | 57.9 | 55.5 | -2.4 | 49.2 | -8.7 |
| | 7. Payment to transmission owners | 2.7 | 3.2 | 0.5 | 4.7 | 2.0 |
| | 8. Total load purchaser benefit -(6+7) | -60.6 | -58.7 | 1.9 | -53.9 | 6.7 |
| | | | | | | |
| Taxpayers | 9. Payment for PTC | 7.8 | 9.9 | 2.1 | 12 | 4.2 |
| | 10. Total taxpayer benefit (-9) | -7.8 | -9.9 | -2.1 | -12 | -4.2 |
| | | | | | | |
| | Total (4+5+8+10) | - | - | 2.0 | - | 4.1 |

** The benefit for the Interregional and MT-DC scenarios is defined as the difference between the benefits of that scenario and the Limited AC scenario. Total benefits are not shown for the individual scenarios because they have practical meaning only when two scenarios are compared.*

# 5 Conclusions

This chapter documents the nodal scenario development, which includes several rounds of production cost modeling and DC power flow steady-state and contingency analysis as well as select economic analysis for the NTP Study. This nodal analysis across three scenarios (Limited, AC, and MT-HVDC) is designed to accomplish two primary objectives: 1) verify the scenarios are feasible given network and operational constraints and 2) provide insights about the role of transmission operations for a range of transmission topologies.

The results of this chapter demonstrate transformative scenarios, where large expansions of new interregional transmission significantly change the operational relationships between transmission planning regions, can reach 90% decarbonization by 2035, and pass preliminary reliability tests, such as select single contingencies. The nodal transmission expansions show long-distance, high-capacity HV and EHV transmission effectively moves power from more remote areas toward load centers, enables bidirectional power transfers between regions, and can also play critical roles in day-to-day balancing intraregionally and interregionally and between nonadjacent regions. Also apparent in developing the three nodal expansions is that transmission can adapt to different types of futures—those that have more local generation such as the Limited scenario, and the interregional expansion scenarios (AC and MT-HVDC), where longer-distance and higher-capacity transmission is deployed. Substantial transmission expansion was required in all the nodal scenarios modeled for this study.

Transmission buildout scenarios using multiterminal and potentially meshed HVDC technology represent the lowest-cost scenarios. However, the magnitude of additional interregional transmission capacity arising from these scenarios is far advanced from existing regional transmission planning and merchant transmission schemes. HVDC network solutions will also require additional strengthening of intraregional AC networks. Moreover, the HVDC scenarios present opportunities for seam-crossing HVDC transmission between the Eastern, Western, and ERCOT interconnections. Study results show this interregional HVDC transmission infrastructure is heavily used.

Limited interregional expansion scenarios can be operated reliably; however, they differ from the AC and MT-HVDC scenarios by having greater local generation ramping and balancing needs (greater need for dispatchable capacity, including clean thermal generation, which exhibits greater variable costs considering fuel needs).

The methods developed for the transmission portfolio analysis are novel in that they could be applied at a large-geographic scale and include both production cost modeling and rapid DC-power-flow-informed transmission expansions. The incorporation of capacity expansion modeling data was also innovative. This is not the first example of closely linking capacity expansion modeling to production cost and power flow models in industry or the research community, but several advancements were made to realistically capture the various network points-of-interconnection for large amounts of wind and solar, build out the local collector networks if necessary, and validate

interregional solutions factor in the local transmission challenges that might arise from scenarios that reach 90% reduction in emissions by 2035.

## 5.1 Opportunities for Further Research

The methods to model the U.S. electricity system with network-level detail and with highly decarbonized systems stretch the data management and computational limits of many methods typically used for power system analysis. In addition, this study reveals many assumptions about the large-scale transmission expansions and power system operations that could be strengthened with further study:

- **Visualization:** Modeling CONUS results in huge amounts of data to manage. Visualization tools have helped the study team rapidly assess the success of a transmission line development or the placement of renewable resources on the network. But additional work on visualizing these systems should continue to be an area of research to speed analysis and allow for easier stakeholder interactions.
- **Network formulations:** Improvements in the representation of network constraints in nodal production cost models should allow improved computational efficiency of branch flow constraints for an increased number of HV/EHV transmission elements.
- **HVDC dispatch strategies and interregional coordination:** Further implement different strategies for the dispatch of point-to-point, embedded HVDC links and MT or meshed HVDC networks in nodal production cost models.
- **Interregional coordination:** Undertake the evaluation of day-ahead and real-time interregional coordination algorithms implicitly considering information asymmetry and uncertainty between balancing areas (plant outages, wind/solar production, and demand).
- **Power flow control devices:** Improve the representation of at-scale grid enhancing technologies (GETs) and power flow controlling device capabilities (e.g., phase-shift transformers and static synchronous series compensators).
- **Direct integration of AC power flow:** Integrating AC power flow across scenarios (see Chapter 4) by adding a stage to the transmission expansion workflow could improve the solutions. However, more work would be needed to develop robust model linkages where feedback from AC power flow could rapidly inform development decisions.
- **Durable contingency sets:** Develop further methods to identify critical contingency sets for various configurations of the future contiguous U.S. grid under many contingency conditions.

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# Appendix A. Methodology

## A.1 Nodal Datasets

Table A-18. Summary of Nodal Baseline Datasets for Contiguous United States (CONUS)

| Quantity (000s) | Eastern Interconnection | Western Interconnection | ERCOT | CONUS |
|---|---|---|---|---|
| Nodes | 95.9 | 23.9 | 6.8 | **126.8** |
| Branches (lines/cables/trafos) | 115.7 | 28.1 | 8.4 | **152.3** |
| Loads | 41.2 | 14.6 | 3.7 | **59.6** |
| Generators | 10.8 | 4.3 | 0.7 | **15.5** |

*ERCOT = Electric Reliability Council of Texas*

Table A-2. Overview of Data Sources Used for Building CONUS Datasets

| Description | Eastern Interconnection | Western Interconnection | ERCOT |
|---|---|---|---|
| Network topology (node/branch connectivity)[1] | MMWG 2031[2] | WECC ADS 2030 v1.5 | EnergyVisuals[5] |
| Node mapping (spatial) | NARIS | NARIS/EnergyVisuals | NARIS |
| Generation capacity (technology) | NARIS | WECC ADS 2030 v1.5 | NARIS |
| Generation techno-economic characteristics[3] | NARIS, EIA CEMS | WECC ADS 2030 | NARIS |
| Demand | EER | EER | EER |
| Hydro (energy constraints)[4] | NARIS | WECC ADS 2030 | NARIS |
| Variable renewable energy (VRE) time series | reV | reV | reV |

*[1] Augmented through stakeholder feedback to include the most recent available data on network updates/additions.*

*[2] ERAG Multiregion Modeling Working Group (MMWG) 2031 series.*

*[3] Includes heat rates, minimum up-/downtimes, ramp rates, and minimum stable operating levels.*

*[4] Hourly/daily/monthly energy budgets (as appropriate).*

*[5] Power flow case files (2021 planning cases).*

*ADS = Anchor Dataset (Western Electricity Coordinating Council, n.d.); CEMS = continuous emission monitoring system; EER = Evolved Energy Research; EPA = U.S. Environmental Protection Agency; MMWG = Multiregional Modeling Working Group; NARIS = North American Renewable Integration Study (National Renewable Energy Laboratory [NREL] 2021b); reV = Renewable Energy Potential Model (Maclaurin et al. 2019); WECC = Western Electricity Coordinating Council*

## A.2 Benefits and Challenges in Implementation of CONUS-Scale Databases

The benefits of implementing CONUS-scale nodal databases are summarized next:

- **Model fidelity:** Increased model fidelity and insights into operations and transmission use (beyond zonal capacity expansion)
- **Discretization:** Identification of discrete interzonal and intrazonal transmission loading, congestion, and expansion needs (including potential transit needs for nonadjacent regions)
- **Data management:** Enabling more seamless data flow and obtaining information to feed forward and feed back to other modeling domains.

Appreciating these benefits, the challenges in implementation are summarized next:

- **Dataset maintenance:** Consistent maintenance of datasets across regions and interconnects to ensure relevance and accuracy is challenging because each region and interconnection applies different approaches when collating data into aggregated datasets. Similarly, regions within each interconnection have varying levels of alignment with interconnectionwide modeling practices.
- **Dataset updates:** Another challenge that has emerged is the potential time lag to the latest available nodal information (specifically demand, generation capacity, and network topologies), which can result in the potential for perpetual chasing of data. This is not necessarily specific to the National Transmission Planning Study (NTP Study) but should be considered for future similar CONUS-scale work to support repeatability and potential periodic updates of CONUS-scale interregional transmission planning efforts.
- **Effort:** The collation of datasets and model building is a data- and labor-intensive undertaking. The NTP Study has established a structured set of workflows to undertake this in future and address this challenge (in addition to the abovementioned challenges of dataset maintenance and updating).
- **Interregional focus:** There is the potential to overly focus on regionally specific intraregional transmission needs and solutions. This can lead to a false sense of accuracy within regions if one deviates from the primary objectives and drivers of the NTP Study (and other similar efforts)—that is, interregional transmission needs and enabling intraregional transmission needs (transit needs).

## A.3 Disaggregation: Adding Generation Capacity to Nodal Models

The process of adding capacity to the nodal model integrates many considerations and is implemented in an internally developed NREL tool called ReEDS-to-X (R2X):

1. Average generator sizes per technology are based on the Western Electricity Coordinating Council (WECC) Anchor Dataset (ADS) data for standard technology-specific generators (Western Electricity Coordinating Council 2022) or the median generator size of the technology in the zone in which it is being added.

2. Nodal injection limits are applied (both for number of units and capacity) to avoid large generator injections and large numbers of generators connected to individual nodes.

3. For variable renewable energy (VRE) technologies, which use a time series for their characterization (fixed injections), the National Renewable Energy Laboratory (NREL) Renewable Energy Potential Model (reV) (Buster et al. 2023) is used in combination with a k-means clustering technique to aggregate wind and solar photovoltaic (PV) sites to points of interconnection (POIs) (Figure 5).

4. Distributed solar PV is prioritized to nodes with high load participation factors (LPFs), aligning with the expected distributed resource location closer to large loads.

5. Heuristics for battery energy storage systems (BESS) are applied by co-locating 4-hour BESS to solar PV POIs and 8-hour BESS to land-based-wind POIs (with a 50% capacity limit). Following this, any remaining BESS capacity is allocated to nodes with high LPFs.

## A.4 Disaggregation: Zonal-to-Nodal Demand

Figure A-1 demonstrates geospatially how a specific Regional Energy Deployment System (ReEDS) zone, highlighted in (a) (Northern Colorado), is disaggregated to the nodal loads within that zone. This is based on the established LPFs of each node for the Northern Colorado zone (shown via the relative size of each of the markers in (b) of Figure A-1).

(a) (b)

Figure A-1. Illustration of zonal-to nodal (Z2N) disaggregation of demand (a) CONUS and (b) zoom to Colorado

*In (a), a single ReEDS zone is highlighted; in (b), a zoom into northern Colorado illustrates individual node load through which LPFs are calculated and zonal ReEDS load is disaggregated.*

## A.5 Transmission Planning Principles

The NTP Study applies several building blocks for the discrete decisions made about the transmission planning process. Where possible, the following principles are applied to expand both interregional and intraregional transmission:

- **Right-of-way expansion:** Expansion of an existing single-circuit to double-circuit overhead line
- **New corridor:** Expansion of a new double-circuit overhead line
- **Voltage overlay:** The ability to move from established voltages to higher-capacity voltage levels, e.g., 345 kilovolts (kV) to 500 kV
- **High-voltage direct current (HVDC):** Termination into well-interconnected areas of existing alternating current (AC) transmission networks with converters of 2-gigawatt (GW) monopole or 4-GW bipole at a time (further details are provided in Appendix A.6).

The increasingly granular representation of network constraints within the staged transmission expansion process is established through the combined monitoring or bounding of flows across preexisting and new interfaces. The study authors collected existing tie-line interfaces from public sources and stakeholders while defining new interfaces between transmission planning region boundaries (based on the aggregated subtransmission regions in Appendix B.2). In addition, interregional tie-lines were always monitored given the interregional emphasis of the study.

The increasingly granular representation of network constraints that forms part of the zonal-to-nodal transmission expansion workflow is shown in Figure A-2. This staged

approach enables the exploration of line loading, congestion, and use to highlight transmission expansion needs while improving model tractability in Stage 1 of the workflow.

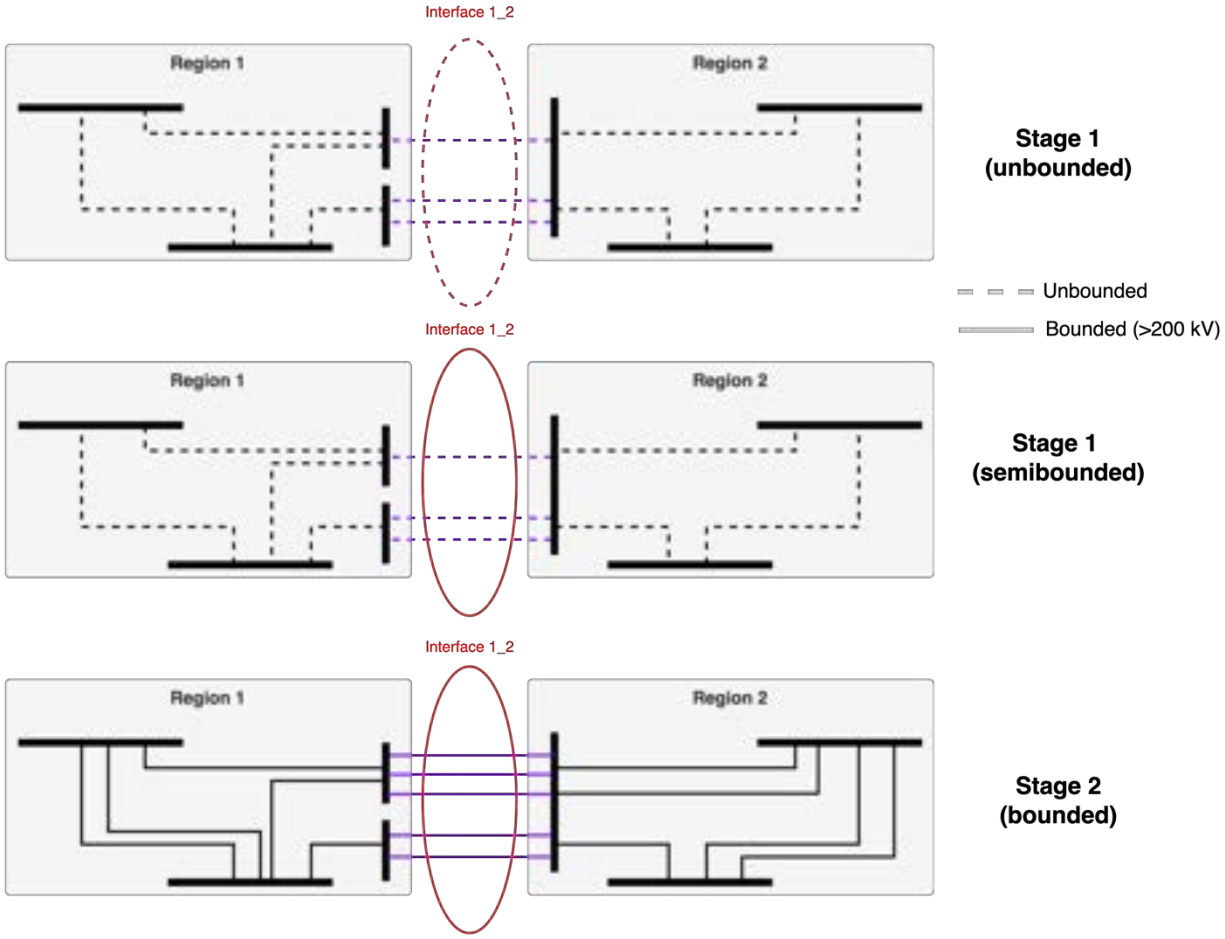



Figure A-2. Illustration of nodal transmission network constraint formulations

## A.6 Transmission Planning Approach for HVDC Networks

The unique nature of HVDC network design (notwithstanding classical point-to-point types of HVDC infrastructure) shifts the staged transmission planning (Figure 6) approach slightly for a scenario with large amounts of multiterminal HVDC zonal investments. This approach is outlined next:

1. **Establish a conceptual topology:** Establish an initial HVDC network focused on the building blocks for HVDC. These are assumed as 2-GW monopole and 4-GW bipole pairs at a time. From this, establish appropriate nodes for discrete HVDC links into the combination of large load zones, large concentrations of generation capacity (particularly VRE), and well-interconnected areas of existing HVAC networks with a capability to absorb/evacuate large amounts of power—that is, areas with good network connectivity, higher voltage levels, and strong short-circuit levels (closer to synchronous generators).

2. **Prioritize large interregional transfers:** Although generation and storage capacity are prescribed from zonal capacity expansion findings, interregional transfer capacity is used as a guide for transferring power between regions to maintain practical realizations of HVDC expansion.[62] Hence, there is a distinct prioritization of large interregional zonal transfers (>10 GW) followed by interregional corridors (2–10 GW) and then other potentially smaller corridors (<2 GW).

3. **Stage 1 (nodal production cost model, initial round):** Set interface limits (similar to the approach outlined in Figure 6) but using existing interface limits from zonal capacity expansion findings. Use an initially large HVDC transfer capacity for the HVDC links portion of the scenario (chosen as 10 GW) and run the nodal production cost model.

4. **Stage 1 (nodal production cost model, next round):** Adapt the HVDC overlay limits (from the initially chosen large capacity, 10 GW), undertake potential relocation of termination points of the HVDC overlay as well as scaling the relative size to established building blocks based on the use of the HVDC overlay and rerun the nodal production cost model.

5. **Stage 2 and Stage 3:** Using the findings from the previous steps, undertake HVAC transmission capacity expansion to support the HVDC overlay as defined in the previously discussed workflow in Figure 6 to ensure secure operations and contingency performance for HVAC expansions and large HVDC expansions. As part of this step, there is the potential need to further refine the HVDC overlay topology.

## A.7 Snapshot Selection Methodology

When using a power flow model—either as an aid to speed up feedback to model changes or to perform contingency screening—it is necessary to select a set of snapshots to perform the calculation. There are many methods to do this; next is a description of two that were used as part of this study.

### Systemwide and region-specific statistics

Table A-3 shows the snapshots characteristics used in the DC power flow transmission planning phase. Using these snapshots resulted in several hundred snapshots per scenario being used to inform the flow impacts of adding different lines.

[62] Building many short-distance HVDC links integrated into a multiterminal HVDC overlay is unlikely to be practical considering the 2035 model year for the zonal-to-nodal translated scenarios—hence, the prioritization approach taken for the zonal-to-nodal translation with respect to HVDC deployment.

Table A-3. Selection of Operating Conditions ("snapshots") From Nodal Production Cost Model for Use in DC Power Flow Transmission Expansion Planning Step

| CONUS | Region-Specific |
|---|---|
| Load<br>• High load periods | Interregional exchanges<br>• Average period for each regional interface<br>• High inter-tie use (P90) |
| Renewable energy production<br>• Peak/high wind + solar<br>• Peak/high wind<br>• Peak/high solar | Regional balancing<br>• High import (P90)<br>• High export (P90)<br>• High load |
| Instantaneous renewable energy<br>• High VRE share in high load period<br>• High VRE share in low load period | Transit flows<br>• High transit flows across "balanced" regions |

*Note: Region-specific refers to transmission planning subregions.*

### Flow-based statistics

The following methodology is used to select the snapshots for the Stage 3 contingency analysis in the ReEDS earlier scenario results. The premise of this approach is the snapshots are used for a specific task: to investigate the impact of topology changes on how flow is distributed through the system. In Stage 2, this is because of a change of topology—for example, new transmission lines but fixed injections. In Stage 3, this is because of a line outage and no change of injections. This observation suggests a sample of snapshots whose flow distribution matches the flow distribution over the full year would capture the behavior of interest.

The flow metric used here is the average flow; however, this can be adapted to U75, or other metrics.

Consider a set of branches $b \in \mathcal{B}$, with ratings $r_b$, and a set of time instances $t \in \mathcal{T}$, which for a year is [1,8760]. The goal is to select a subset of time $\mathcal{K} \subset \mathcal{T}$. Define $f(b,t)$ as a function that returns the flow on branch $b$ at time $t$, $p(b,\mathcal{T})$ as a function that returns all time instances $t \in \mathcal{T}$, where the flow on $b$ is positive and similarly $n(b,\mathcal{T})$ as a function returning all time instances where flow on $b$ is negative. Crucially, note all flows are known a priori because a solved production cost model is available.

The average positive and negative flows on branch $b$ are calculated as

$$\bar{b}_+ = \frac{1}{r_b|\mathcal{T}|}\sum_{t\in p(b,\mathcal{T})} f(b,t)\,, \qquad \bar{b}_- = \frac{1}{r_b|\mathcal{T}|}\sum_{t\in n(b,\mathcal{T})} f(b,t).$$

These values are combined for all branches into a vector $\vec{b}$. Similarly, the estimated branch flows based on the snapshots are defined as

$$b^\star_+ = \frac{1}{r_b K}\sum_{t\in p(b,\mathcal{T})} u_t \cdot f(b,t)\,, \qquad b^\star_- = \frac{1}{r_b K}\sum_{t\in n(b,\mathcal{T})} u_t \cdot f(b,t).$$

Here, $K = |\mathcal{K}|$ is the number of desired snapshots and $u_t$ is a binary variable (8,760 variables in total). All these variables are combined into a single vector, $\vec{b}^{\star}$. So only $K$ snapshots are selected, the following constraint is enforced:

$$\sum_{t \in \mathcal{T}} u_t = K.$$

Finally, the objective function is

$$\text{Minimize}_{\vec{b}^{\star}, \vec{u}} \left\| \vec{b}^{\star} - \vec{b} \right\|_1$$

minimizing the $L_1$ norm of the difference between the vector of average flows over all time instances and the one calculated for just the selected $t \in \mathcal{K}$. The selected snapshots are those where $u_t = 1$ at the end of the optimization.

## A.8 Alternative Approach for Contingency Analysis for Western Interconnection Focused Analysis

The methodology for contingency analysis for the earlier scenarios for the Western Interconnection (results presented in Section 4) is modified from that explained in Section 2.3. The method employed incorporates single contingencies into the production cost model, turning the formulation into a security-constrained one. First, a DC-power-flow-based contingency analysis is performed as a screen on selected single contingencies, as described previously. The violations are pared down to the worst violations that must be addressed. For example, if a particular line overloads in several snapshots by a significant amount but is otherwise not very highly used, the question of where the right place to add transmission quickly becomes rather complex. The result is a limited set of security constraints comprising a handful of single line contingencies with a small number of monitored affected elements per contingency. These are added to the production cost model and a new year simulation is performed A benefit of the security-constrained approach is the results contain congestion costs associated with the contingency constraints, which makes it possible to sort and rank the constraints based on their impact to the problem objective. The costliest security constraints are the most valuable to upgrade for the system. Where the congestion cost is low, the security constraint can be maintained, and no further action taken. This methodology is demonstrated on the Western Interconnection cases, because the GridView tool—used to solve these models—can incorporate such security constraints. Note as the case sizes increase, so does the computational burden of contingency constraints. Depending on the number of security constraints considered and the model size, there may be a point where the computational costs outweigh the benefits of this approach.

## A.9 Impact of Branch Monitoring on Transmission Expansion Workflow in Earlier ReEDS Scenarios

For the simulations conducted on the Western Interconnection footprint only (Limited and AC scenarios), the limits of all branches with voltage rating 230 kV and above were enforced, or approximately 4,000 branches. In the Multiterminal (MT)-HVDC scenario,

the limits on all branches with voltage rating 345 kV and above are enforced, as well as select 230-kV branches observed to violate their limit, for a total of ~6,000 branches. All flows on branches 230 kV and above are recorded, however, and as shown in Figure A-3 the resulting violations are not very significant (~1%).

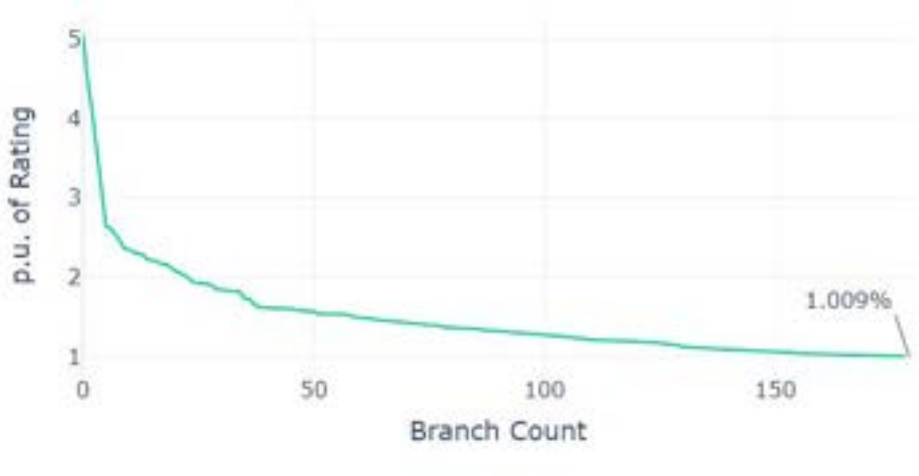



Figure A-3. Branch loading in the MT-HVDC scenario

*Chart shows branches rated ≥200 kV and ≥250 megavolts-ampere (MVA) that violate their nominal rating. Despite not enforcing all branches as in the Western Interconnection only cases, the number of violations remains quite small (at only 1%).*

The number of enforced lines in the earlier scenarios is a factor of 2–4 greater than in the final scenarios. This results in greater sensitivity of generator dispatch to the changing topology, i.e., transmission expansion. A consequence of the increased sensitivity is the DC power flow step in Stage 2 (cf. Section 2.3) of the transmission expansion becomes more challenging to interpret because an underlying assumption of iteration with the DC power flow is an unchanged generation dispatch. Therefore, the DC power flow is not relied on in Stage 2 in the earlier ReEDS scenarios. On the other hand, in Stage 3, where select single contingencies are considered, the DC power flow is still used extensively as a valuable contingency screening tool. The methodology for selecting representative snapshots is described under flow-based statistics in this appendix.

## A.10 Design Approach for a Nationwide MT-HVDC System in Earlier ReEDS Scenario (demonstrated in Section 4)

Modeling large MT-HVDC systems, embedded in AC interconnects, in production cost models is an emerging area (Nguyen et al. 2024). The flows within each MT-HVDC system are determined by shift factors, very similar to the power transfer distribution factors (PTDFs) in the linearized AC system. Converter models are added as control variables that link AC and DC buses.

The objective of the MT-HVDC scenario is to explore the implications of a large-scale MT-HVDC system covering a large portion of the country. A design decision on the earlier ReEDS scenarios is to use a single design that would facilitate combining segments. All new HVDC lines modeled in this scenario are ±525-kV voltage source

converter (VSC) bipole design with conductor parameters adapted from the CIGRE Working Group (WG) B4.72 DC Benchmark Models (CIGRE WG B4.72 2022, 804). The rating of a single bipole does not exceed 4.2 GW.

Converter stations are sited based on the underlying AC system. They are embedded in the AC system at comparatively strong/well-meshed locations to enable delivery to/from the DC system as well as provide a viable alternative path during contingency events. Converter locations can be grouped into three categories: VRE hubs, load centers, and connection points to AC transmission hubs.

HVDC transmission is generally chosen for two key reasons: high power transfer over large distances and flow controllability. MT-HVDC systems have the benefit of fewer converters than point-to-point systems and therefore lower capital costs; meshed MT-HVDC systems have the additional advantage over radial systems of reliability under failure because of alternative current paths. Reduced converter count in MT-HVDC systems comes at the cost of increasing mismatch between line and converter rating, depending on whether each converter on the line operates as a source or a sink. Reliability in meshed MT-HVDC systems comes at the cost of some loss in controllability because the flow distribution between parallel paths will be the function of shift factors, similar to the AC system.

The design choice in the MT-HVDC scenario presented in Section 4 of this chapter is a compromise between the costs and benefits of the three frameworks described previously. First, several MT-HVDC systems that are largely radial are created. At their intersections, they do not share a DC bus but rather an AC bus between a pair of converters,[63] as shown in Figure A-4. This solution sacrifices some of the cost saving of MT-HVDC, because of the additional converter, but gains back more controllability while maintaining the reliability of a system with multiple paths for power to flow. The final HVDC topology is presented in Figure A-5, which shows HVDC expansion color coded to highlight the separate MT-HVDC systems.

[63] Note a converter here actually refers to the converter pair ±525 kV, given the bipole design.

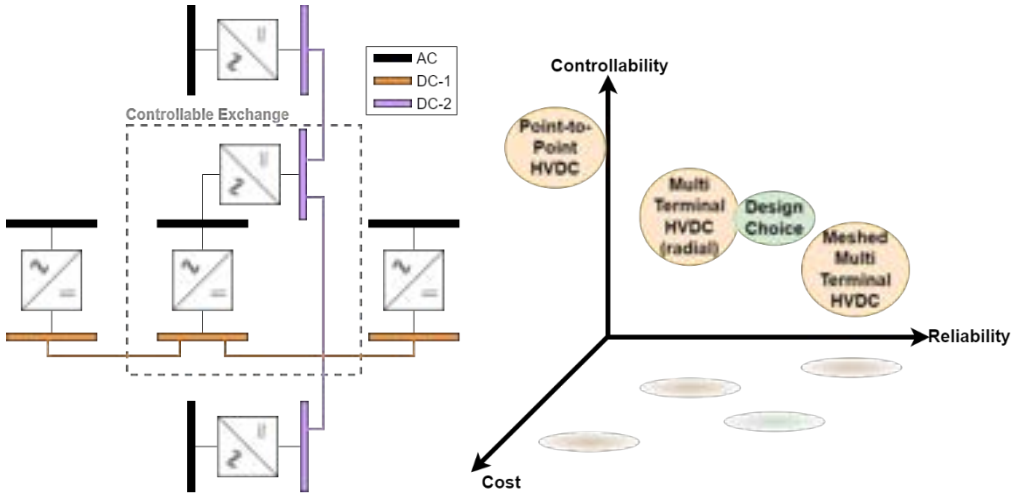



Figure A-4. Coupled MT-HVDC design concept and rationale

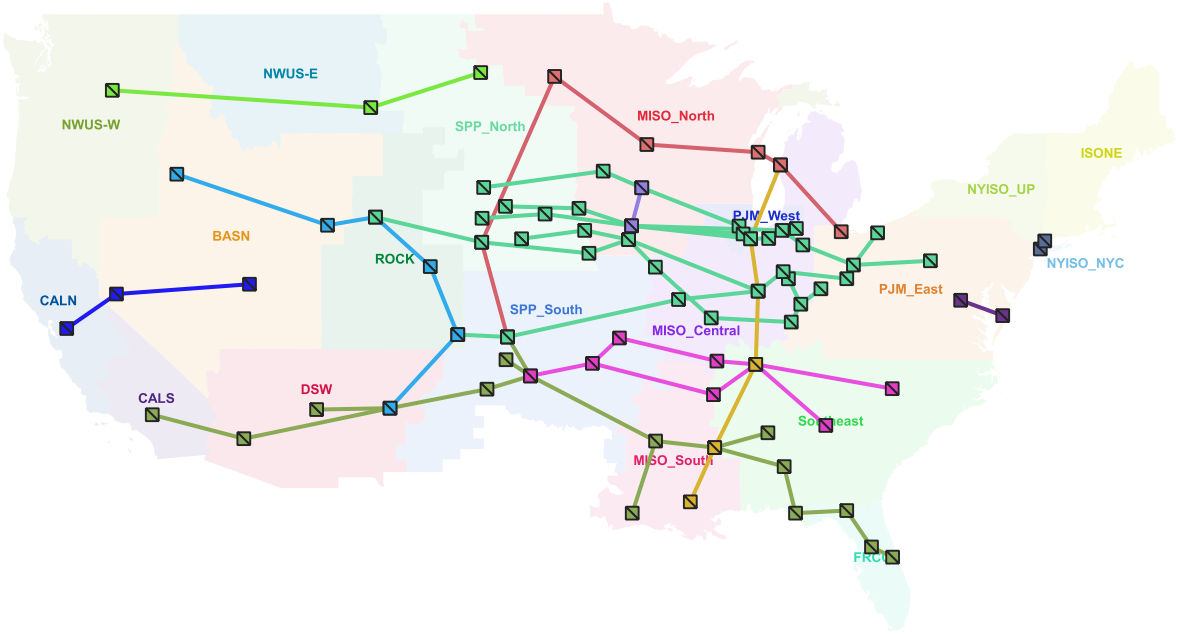



Figure A-5. HVDC buildout in the MT-HVDC scenario

*Different colors correspond to separate MT-HVDC systems interconnected via the AC system as illustrated in Figure A-4.*

# Appendix B. Scenario Details

## B.1 New Transmission Network Elements

Table B-1. Nodal Transmission Building Block Characteristics (overhead lines)

| Voltage (kilovolts [kV]) | Conductor | Pos. Seq. R (ohms per kilometer [Ω/km]) | Pos. Seq. X (Ω/km) | Rate (MVA) | Source |
|---|---|---|---|---|---|
| 230 kV | 2 x Bluejay | 0.0299 | 0.3462 | 703 | (1) |
| 345 kV | 2 x Bluejay | 0.0299 | 0.3579 | 1,055 | (1) |
| 345 kV | 3 x Bluejay | 0.02 | 0.3127 | 1,566 | (1) |
| 500 kV | 4 x Grosbeak | 0.0259 | 0.3145 | 2,187 | (1) |
| 500 kV | 4 x Bluejay | 0.0152 | 0.3105 | 3,027 | (1) |
| 500 kV | 6 x Bluejay | 0.0102 | 0.2186 | 3,464 | (1) |
| 765 kV | 6 x Bluejay | 0.0105 | 0.2831 | 5,300 | (1) |
| HVDC (525 kV) | Bobolink | 0.0099 | N/A | 2,100 | (2) |

*Sources:*

*Empresa de Pesquisa Energética (EPE) (2022)*

*CIGRE WG B4.72 (2022)*

Table B-2. Nodal Transmission Building Block Characteristics (transformation capacity)

| Voltage (kV) | X (p.u. on Transformer MVA base) | Rate (MVA) |
|---|---|---|
| 345/230 | 0.12 | 2,000 |
| 500/230 | 0.12 | 2,000 |
| 500/345 | 0.12 | 2,000 |
| 765/500 | 0.12 | 2,000 |

In the earlier ReEDS scenario results, an analysis of transformers in the Western Electricity Coordinating Council (WECC) starting case (2030 Anchor Dataset [ADS]) shows the relationship between transformer MVA base and per unit reactance on the system basis could be approximately described as

$$x[\text{p.u.}] = 0.0523 \ln(MVA) - 0.2303.$$

This formula is used to calculate variable reactance, under the assumption the transformer base and rating are equal.

Converter losses are estimated on a per unit basis as

$$R[\text{p.u.}] = \text{loss}_{\%} / P_{\text{Rated[MW]}}$$

Where 0.7% is assumed for line-commutated converter (LCC) technology and 1.0% for voltage source converter (VSC) technology. Though the production cost models are conducted without losses, these values are important for the downstream power flow models in Chapter 4, where a full alternating current (AC) power flow that includes losses is conducted.

## B.2 Region Definitions

Figure B-1. Subtransmission planning regions (derived and aggregated from Regional Energy Deployment System [ReEDS] regions)

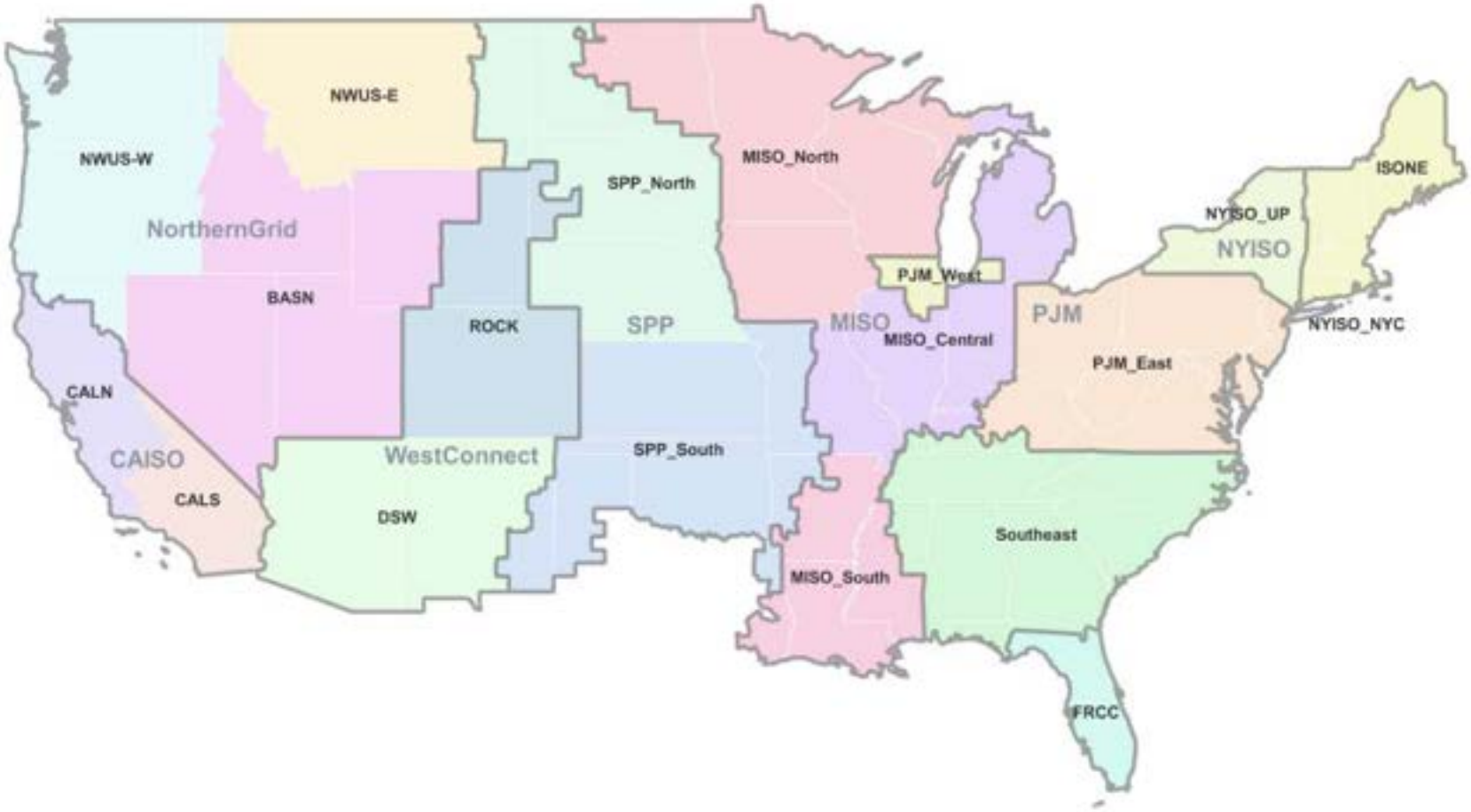



Figure B-2. Subregion definitions used in Section 4 (earlier ReEDS scenario results)

*The definition of regions is based on the underlying 134 ReEDS regions (excluding Electric Reliability Council of Texas [ERCOT] regions).*

## B.3 Detailed Motivation for Transmission Expansion for Earlier ReEDS Scenarios

The following sections describe the key transmission additions and their rationale on a regional basis. For the Western Interconnection footprint, comparisons between the scenarios are given whereas for the Eastern Interconnection regions, the description is for the Multiterminal (MT) High-Voltage Direct Current (HVDC) scenario only.

### California (CALS and CALN)

All scenarios have some intraregional transmission expansion, particularly in southern California to help the large amount of solar power get to load. Northern California has a few 500-kilovolt (kV) backbone changes associated with offshore wind integration that are based on plans in California Independent System Operator's (CAISO's) 20-year outlook.[64]

In the interregional scenario, the connection to the Desert Southwest (DSW) and Basin region is strengthened both via Nevada as well as along the southern border. This is mirrored in the MT-HVDC scenario with an MT-HVDC connection to the Lugo substation. In the interregional scenario, a 500-kV backbone on the eastern part of the state is added to increase the transfer capacity between northern and southern California. In all cases, the transmission is primarily motivated by bringing external resources *into* California, primarily eastern wind. However, the transmission capacity also serves to *export* California solar energy during the daily peaks.

### Northwest (NWUS-W and NWUS-E)

In all scenarios, some form of a 500-kV collector system is added to collect wind in Montana and attach it to the Colstrip 500-kV radial feed. In the two AC cases, a new line from Garrison to Midpoint is used to provide an alternative export to WECC Path 8 and a connection to the Gateway projects. In the MT-HVDC case, WECC Path 8 is effectively reinforced with an MT-HVDC line connecting North Dakota and the Ashe substation in Washington, with a terminal in Colstrip in between.

### Desert Southwest (DSW)

The desert southwest is one of the more varied regions in terms of transmission, driven by very different resource buildouts between the scenarios. In the limited AC scenario, the region has substantially (≥20 GW) more solar capacity installed than the other two cases. The 500-kV system along the southern border is reinforced and expanded to collect that solar energy and bring it to load. In the interregional scenario, substantially more wind (~11 GW) is installed, predominantly in New Mexico, necessitating a significant 500-kV backbone expansion. The energy is provided in three main paths: north via Four Corners, west via Coronado, and south toward Phoenix. The MT-HVDC scenario has a lower solar build, like the interregional AC scenario, and a wind build somewhere between the Limited and interregional scenarios. As a result, the AC expansion is not as extensive as the interregional scenario but taken together with the

[64] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

DC scenario forms a similar three-corridor design to get both New Mexico wind as well as wind from across the seam to the Eastern Interconnection toward the western load pockets.

A commonality between all scenarios is the reinforcement of the 500-kV corridor across northern Arizona into Nevada. This is driven by the ability of the transmission to carry both solar from southern Utah/northern Arizona that is present in all scenarios as well as the wind out of New Mexico via Four Corners when present.

### Rocky Mountain (ROCK)

The 345-kV system around Denver is expanded to bring in predominantly wind resources. To the south, the Colorado Power Pathway[65] is part of the augmented starting case and is expanded on in the scenarios. To the north, connections to the Cheyenne and Laramie River region in Wyoming are added. Two paths are generally used—one to the Public Service Company of Colorado and one to the Western Area Power Administration systems.

The Gateway projects are also added in all scenarios as part of the augmented starting case. They are expanded in all scenarios to collect more of the Wyoming wind. In the limited AC case, with less wind, this is done with mainly 230-kV reinforcements. In the interregional AC and MT-HVDC cases, a northern 500-kV section is added between the Windstar and Anticline substations.

The TransWest express[66] DC and AC projects are incorporated into the augmented starting case and bring wind from Wyoming toward the Desert Southwest and California.

The Rocky Mountain region is loosely connected to the rest of the Western Interconnection compared to the other regions. One of the key differences between the limited AC scenario and the others is the connection between the Rockies and other regions. In the interregional AC scenario, there is a connection to New Mexico via the 500-kV backbone built to collect wind. In the MT-HVDC scenario, an HVDC backbone connects the Rocky Mountain region to the Basin via Wyoming, to the Desert Southwest via New Mexico, and to Southwest Power Pool (SPP) to the east.

### Basin (BASN)

In the modeled scenarios, the Basin region plays a key role in providing multiple paths for resources to reach load. The projects involving the Basin region largely begin/end in other regions: Montana, Rocky Mountain, Desert Southwest, Pacific Northwest, or California and are therefore not repeated here. The MT-HVDC scenario builds on this connector role for the Basin with two east-west corridors: one toward the Pacific Northwest and one toward the Bay Area in California.

[65] https://www.coloradospowerpathway.com/
[66] https://www.transwestexpress.net/

### SPP

The transmission expansion in SPP is focused on the east and west movement of wind but some solar in the southern areas as well. To that end, multiple HVDC corridors begin in the SPP footprint and move east or connect across the seam to the Western Interconnection. In addition, a north-south corridor connects to Midcontinent Independent System Operator (MISO) and allows resources to shift between the various east-west corridors. Finally, the wind in the southern part of SPP is intended to complement solar in both Florida and California via an MT-HVDC corridor stretching from coast to coast along the southern part of the country.

In addition to the MT-HVDC, a complementary 345-kV collector backbone is added along the north-south axis on the SPP footprint. The intention is to both collect the VRE resources and provide an alternative path under contingency events.

A 500-kV loop interconnects with MISO in the southern end of the footprint as an alternative path east for wind resources in SPP and to provide better access to load and the MT-HVDC system for solar resources in MISO.

### MISO

An MT-HVDC system runs north-south along MISO's eastern portion to provide exchange between solar- and wind-rich regions as well as a path to the Chicago, Illinois load center. The east-west MT-HVDC corridors originating in SPP include multiple terminals in MISO to serve load and collect further resources toward the east. The east-west corridors terminate at three types of destinations: load centers in PJM and the southeast, solar hubs in PJM and the southeast, or strong 765-kV substations in PJM's footprint that can carry the power farther east to the coast.

In terms of AC expansion, Tranch 1[67] additions are added to the MISO footprint along with further reinforcements of the 345-kV system.

### PJM

The MT-HVDC connections to PJM are largely described in the SPP and MISO sections. It is noted here Chicago serves as an MT-HVDC hub for several east-west lines as well as the north-south MISO system. Finally, the north-south SPP MT-HVDC system loops east and terminates in PJM between Toledo, Ohio and Cleveland, Ohio.

Some of the 765-kV segments of the PJM system are upgraded to enable eastward transfer of more power coming from the MT-HVDC systems.

Along the Eastern Seaboard, there is a new DC link across the Chesapeake Bay and a 230-kV collector system for solar and offshore wind between Delaware and Maryland.

[67] https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf

### Southeast

Beyond the MT-HVDC systems terminating in the southeast, as described in the SPP and MISO sections, 500-kV reinforcements are built to connect predominantly solar resources to load or the MT-HVDC overlay. Examples are 500-kV connections between Panama City, Mobile, and Montgomery, Alabama and lines from Charlotte, North Carolina down to Augusta, South Carolina.

### FRCC

An MT-HVDC link connects FRCC to the southeast and farther west, intended to import wind from the middle of the country during the night and export the Florida sun in the middle of the day. In addition, a 500-kV backbone is extended from the central Florida region north to further collect solar resources in the northern part of the state and get them toward load centers on the coasts and to the south.

### NYISO

A new HVDC link connects Long Island, New York to Connecticut. Several 345-kV upgrades are also performed on Long Island to accommodate offshore wind projects. The Northern NY Priority, Champlain-Hudson Power Express, and Clean Path NY are also added by default to augment the starting case.

### ISONE

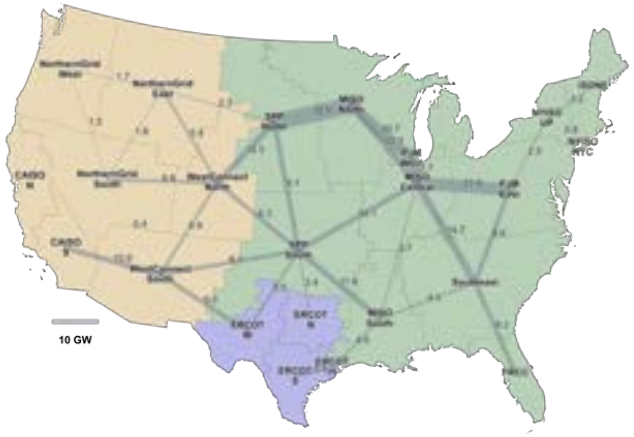
Here, 345-kV collector systems are added in Maine, New Hampshire, and Vermont to collect new wind and solar resources and connect them to the existing 345-kV backbone.

## B.4 Further Detailed Results for Final Scenarios

**Zonal (2020)**

**Limited (2035)**

**AC (2035)**




**MT- HVDC (2035)**

Figure B-3. Interregional transfer capacity from zonal ReEDS scenarios

*Aggregated to transmission planning regions (some larger regions are further subdivided to aid in planning).*

## Detailed installed capacity (by scenario)

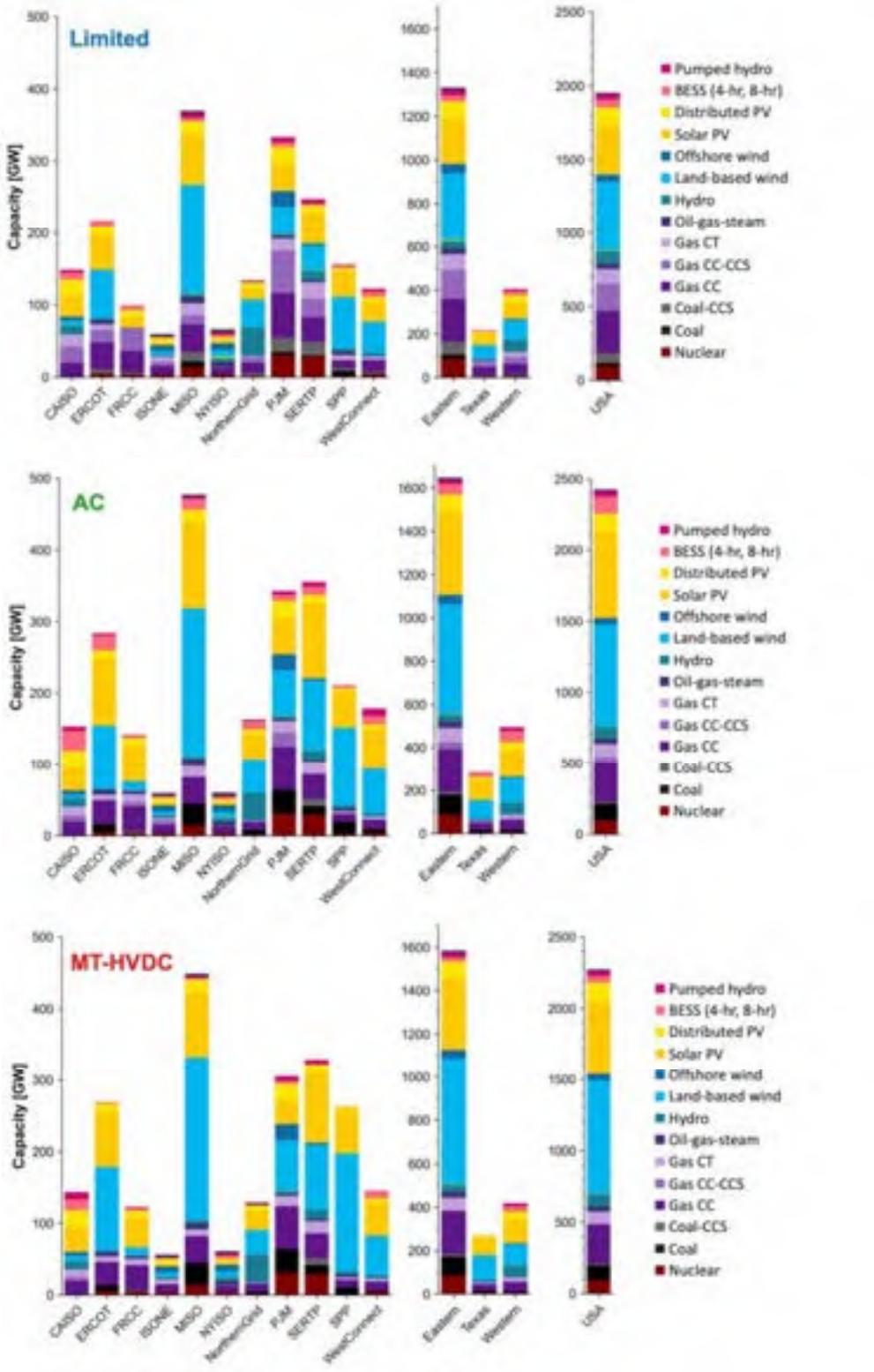



Figure B-4. Summary of installed capacity by transmission planning region, interconnection and contiguous U.S. (CONUS)-wide

## Nodal scenarios transmission expansion summary

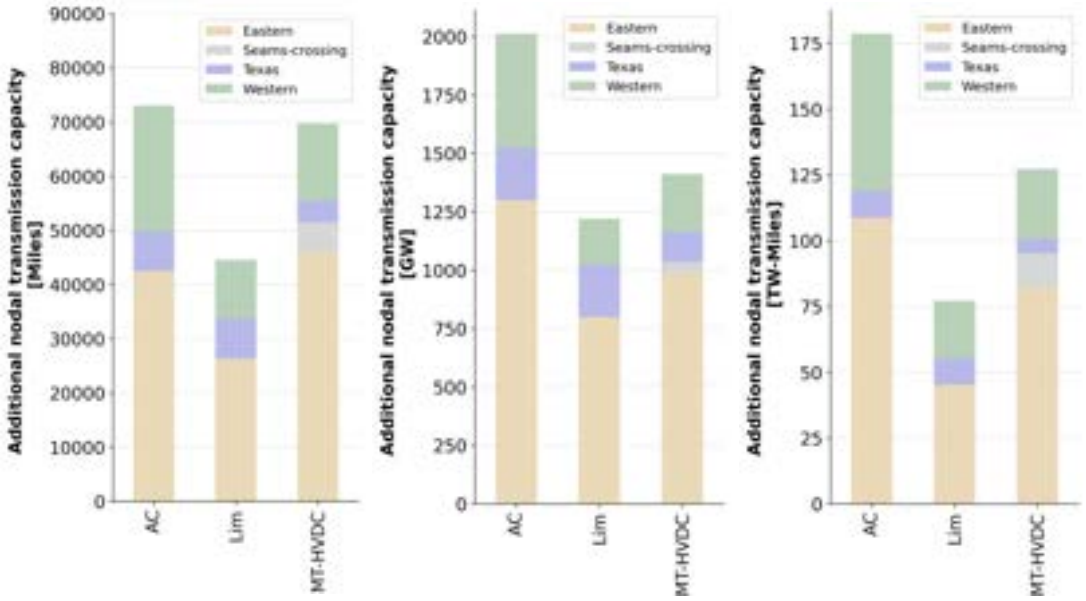



Figure B-5. Summary of nodal transmission expansion portfolios

*Shown for AC, Limited, and MT-HVDC scenarios in terms of circuit-miles (left), thermal power capacity (middle), and terawatt-miles [TW-miles] (right).*

## Detailed nodal scenarios transmission expansion motivation

Table B-3. Rationale for Nodal Transmission Portfolios (Limited scenario)

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| Eastern Interconnection | FRCC | - Significant solar photovoltaics (PV) expansion in the central-eastern side of Florida with large amounts of existing natural gas capacity remaining online<br>- Localized integration of new solar PV capacity does not require interregional transmission expansion with the Southeast<br>- Exiting 500-kV and 230-kV networks suffice for this scenario |
| Eastern Interconnection | ISONE | - Predominantly solar PV and offshore wind integration to the southern parts of New England<br>- No new 345-kV expansions necessary with New York Independent System Operator (NYISO) |
| Eastern Interconnection | MISO | - Inclusion of MISO Long-Range Transmission Planning (LRTP) Tranche 1 (several new 345-kV lines) across MISO-N and MISO-C (prescribed expansion)<br>- 345-kV reinforcements in southern part of MISO-C and 500-kV reinforcements in MISO-S to accommodate integration of new wind and solar PV capacity<br>- Additional 345-kV reinforcements in weak parts of MISO-N to strengthen existing network to integrate predominantly new wind capacity and move power east-west toward load centers in MISO-N and PJM-W |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | - Reinforcement of selected parts of the existing 765-kV network in MISO-C to integrate with PJM-E and PJM-W |
| Eastern Interconnection | NYISO | - Addition of prescribed transmission (Northern NY Priority, Champlain-Hudson Power Express, and Clean Path NY)<br>- Strengthening of existing 500-kV links in NYISO-NYC with PJM<br>- 345-kV expansion to move power across to Long Island<br>- Selected parts of NYISO-NYC 230-kV localized strengthening of existing circuits to enable solar PV integration<br>- 345-kV strengthening NYISO-UP (upstate) from Buffalo toward PJM (north-south) and new 345-kV along the edges of Lake Erie toward Cleveland |
| Eastern Interconnection | PJM | - Development of a 500-kV overlay (double-circuit) in Maryland/Delaware area to support integration of large volumes of offshore wind and solar PV<br>- Strengthening of existing single-circuit 500-kV paths (north-south) in New Jersey and Pennsylvania and parts of Virginia<br>- East-west Pennsylvania 500-kV strengthening of existing single-circuits increasing transfer capacity between 345-kV, 500-kV, and 765-kV networks<br>- Strengthening of many of the existing single-circuit 765-kV network in the PJM-East footprint (Ohio, West Virginia, Virginia) to increase transfer capacity with MISO-Central and PJM-West footprints<br>- Selected strengthening of 345-kV networks in single-circuit to double-circuit at the confluence of the 345-kV, 500-kV, and 765-kV networks in PJM-East as well as interregionally with MISO-Central<br>- Imports into the PJM-West footprint are enabled by some single-circuit to double-circuit strengthening of 345-kV networks within PJM-West and links to MISO-Central |
| Eastern Interconnection | Southeast[2] | - Large amounts of meshed single-circuit to double-circuit 500-kV network strengthening in Tennessee, Mississippi, and Alabama (less strengthening in Georgia and the Carolinas)<br>- Several new double-circuit 500-kV between Alabama and Georgia<br>- Relatively strong 230-kV networks in the Carolinas and Georgia enable integration of expected solar PV, but some 230-kV single-circuit to double-circuit strengthening is needed in southern parts of Alabama and South Carolina |
| Eastern Interconnection | SPP | - Reinforcement of 345-kV network north-south in SPP-North to accommodate integration of new wind capacity<br>- Some localized 230-kV strengthening to collect relatively large amounts of wind capacity<br>- Expansion of 345-kV network in SPP-South to integrate large amounts of wind and solar PV capacity and move power west-east and further into the central parts of SPP toward seams with MISO-Central<br>- Pocket in SPP-South with large amounts of wind and solar PV (Texas panhandle and eastern edge of New Mexico) |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | require substantial 230-kV strengthening and 345-kV exports north toward Kansas and west-east to Oklahoma |
| Western Interconnection | CAISO | - CAISO-North expansion of 500-kV to integrated offshore wind and solar PV combined with strengthening of existing single-circuit 500-kV routes<br>- Selected 230-kV expansions in CAISO-North to integrate solar PV and enable power to move south toward load centers |
| Western Interconnection | NorthernGrid | - In addition to prescribed Boardman-Hemingway, Greenlink Nevada, and TransWest Express, additional 500-kV double-circuit between Wyoming and Montana is added to move large amounts of wind capacity from Wyoming<br>- Strengthening of 500-kV path on the NorthernGrid West edge (single-circuits to double-circuits) in Oregon for parts of offshore wind integration and as an additional path for power from wind in Wyoming and Idaho |
| Western Interconnection | WestConnect | - 500-kV expansion from Wyoming north-south toward Colorado, including extensive 230-kV strengthening to collect large amounts of wind capacity<br>- Further 345-kV and 230-kV expansion in CO (in addition to Colorado Power Pathway) to enable further paths for large amounts of wind capacity farther south toward New Mexico and Arizona<br>- 345-kV strengthening in WestConnect South (single-circuits to double-circuits) moving wind and solar PV capacity east-west toward load centers in Arizona and California<br>- Additional 500-kV path created between New Mexico and Arizona also to move large amounts of wind and solar capacity |
| ERCOT | ERCOT | - Several new double-circuit 345-kV expansions from West Texas toward Dallas-Fort Worth (west-east) and southeast toward San Antonio and Austin<br>- Further strengthening of existing 345-kV single-circuit routes similarly moving large amounts of wind capacity toward load centers<br>- Northern parts of ERCOT also further strengthened with new double-circuit 345-kV expansions also moving large amounts of wind capacity from northern parts of ERCOT and solar PV from eastern parts of Texas toward load centers in Dallas-Fort Worth<br>- Several new double-circuit 345-kV north-south expansions between Dallas and Houston and links to San Antonio and Austin created to further move west Texas wind capacity and solar in south Texas to load centers |

*[1] Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).*

*[2] SERTP/SCRTP*

Table B-4. Rationale for Nodal Transmission Portfolios (AC scenario)

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| Eastern Interconnection | FRCC | - Large amounts of solar PV capacity are supported by relatively strong existing 230-kV networks, but additional strengthening in central and southern parts of the Florida Reliability Coordinating Council (FRCC) footprint are needed<br>- New double-circuit 500-kV interregional links created to the Southeast region (Florida to Georgia) to enable large interregional power flows between FRCC and the Southeast |
| Eastern Interconnection | ISONE | - Strengthening of existing single-circuit 345-kV to double-circuit 345-kV between Independent System Operator of New England (ISONE) and NYISO (upstate) – Massachusetts – New York, Connecticut – New York<br>- Additional 345-kV strengthening between Maine and New Brunswick |
| Eastern Interconnection | MISO | - Large amount of 345-kV expansion (north-south) along Lake Michigan to move substantial wind capacity toward load centers<br>- Large amounts of further 345-kV strengthening in MISO-North on seams with SPP-North<br>- Two new 500-kV double-circuit overlays (west-east) in MISO-North up to SPP-North seams to move large wind and some solar PV capacity across Minnesota and Wisconsin as well as Iowa and Nebraska to load centers in Illinois<br>- Two new 500-kV double-circuit overlays in MISO-Central with additional double-circuit (north-south) to linking MISO-Central and SPP-South moving large amounts of wind capacity (predominantly for west-east transfers) but with supplementary new 500-kV overlay (north-south) improving contingency performance from Kansas to Missouri and Illinois<br>- MISO-Central requires substantial strengthening of the existing 345-kV networks (in addition to prescribed LRTP Tranche 1 projects) to integrate substantial wind and solar PV capacity while creating critical enabling links between SPP and PJM-East footprint (mostly single-circuit to double-circuit expansion)<br>- Strengthening of the existing 765-kV networks in Indiana (MISO-Central) as a backbone for moving wind and solar PV into PJM-West as well as into PJM-East footprints; no new 765-kV rights-of-way required<br>- Large amounts of wind capacity are integrated and moved west-east via new 500-kV voltage overlays in MISO-South to interconnect with SPP-South and the Southeast region as well as strengthening of existing 500-kV ties with MISO-South and the Southeast |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | - Substantial amount of 230-kV strengthening in MISO-North (Minnesota and North Dakota); all single-circuit to double-circuit expansions |
| Eastern Interconnection | NYISO | - New double-circuit 345-kV overlay (from 230-kV) in NYISO combined with strengthening of existing 345-kV in NYISO (upstate) Buffalo area with PJM-West<br>- Further strengthening of existing 345-kV interregional link between NYISO (updates) and PJM-West |
| Eastern Interconnection | PJM | - Development of a 500-kV overlay (double-circuit) in Maryland/Delaware area to support integration of large volumes of offshore wind and solar PV<br>- Large amounts 500-kV single-circuit to double-circuit strengthening along eastern part of PJM-East (Virginia, Pennsylvania, Maryland) enabling further offshore wind integration and moving power—predominantly solar capacity—from the Southeast into PJM-West<br>- Imports into the PJM-West footprint are enabled by some single-circuit to double-circuit strengthening of 345-kV networks within PJM-West and links to MISO-Central<br>- Interregional links strengthened via 345-kV and 500-kV strengthening with NYISO<br>- Central parts of Pennsylvania 345-kV and 500-kV confluence strengthened further (single-circuit to double-circuit)<br>- Many of the existing 765-kV circuits in PJM-West strengthened to enable bulk movement of power interregionally between MISO-Central and the Southeast as well as integration and key links with strengthened 345-kV and 500-kV networks<br>- 500-kV voltage overlay and meshing of existing 345-kV networks in Kentucky to increase transfer capacity with the Southeast region<br>- PJM-West footprint includes strengthening of existing 345-kV circuits (double-circuits) to enable imports from MISO-Central and MISO-North in addition to 500-kV voltage overlay from MISO-North |
| Eastern Interconnection | Southeast[2] | - Several interregional ties with PJM-East region are further strengthened in addition to new 500-kV double-circuit expansions (North Carolina, Virginia, Kentucky, Tennessee)<br>- Strengthening of existing 500-kV ties with MISO-South to move solar and wind capacity bidirectionally between Southeast and MISO-Central/MISO-South (Tennessee, Arkansas, Mississippi, Louisiana, Alabama)<br>- Construction of an additional 500-kV circuit across existing 500-kV ties with FRCC<br>- Large number of 230-kV intraregional strengthening in the Carolinas considering the large amount of solar PV and wind capacity expanded |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| Eastern Interconnection | SPP | - Large 500-kV voltage overlays in SPP-South (from 345-kV) across five paths into the Texas panhandle, across Oklahoma, up into Kansas and west-east toward Missouri enabling interregional expansion and movement of large amounts of wind capacity to Southeast and MISO-Central.<br>- Similar 230-kV expansions in SPP-South to the Limited scenario in Texas panhandle and parts of New Mexico to export wind capacity north and east toward Oklahoma, Kansas, and Missouri<br>- 500-kV overlay (from 345-kV) in SPP-North to move large wind and solar PV capacity interregionally to MISO-North (west-east)<br>- Extensive 345-kV strengthening in SPP-North (multiple paths) moving power southeast to link with MISO-North 345-kV networks linking to the 500-kV overlay in MISO-North<br>- New 500-kV double-circuit overlays (from 345-kV) increasing interregional transfer capabilities between SPP-North and MISO-North |
| Western Interconnection | CAISO | - New double-circuit 500-kV paths (x2) in CAISO-North to integrate offshore wind backbone into existing 500-kV north-south paths<br>- Expansion of single-circuit 500-kV circuits to double-circuit 500-kV in main interregional transfer corridor between California and Oregon<br>- New 500-kV double-circuit expansions between CAISO-North and CAISO-South<br>- Extensive strengthening of existing 500-kV paths from Nevada (x4) into California (CAISO-South) enabling imports of large amounts of wind capacity and solar PV capacity from WestConnect and NorthernGrid-South<br>- 500-kV overlay of existing 230-kV networks in CAISO-South with WestConnect-South moving large amounts of solar PV and wind capacity from Arizona and New Mexico |
| Western Interconnection | NorthernGrid | - New 500-kV to expand the transfer capacity between the West and South<br>- Further strengthening of 500-kV expansions in Nevada (in addition to TransWest Express and Greenlink Nevada) to enable north-south transfer from NorthernGrid-East and NorthernGrid-South<br>- In addition to Boardman-Hemingway, further additional new double-circuit 500-kV paths are created (north-south) moving capacity through Idaho and toward Washington<br>- Strengthening existing east-west 500-kV transfer capacities between Idaho and Oregon (single-circuit to double-circuit) |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | in addition to north-south 500-kV strengthening between Oregon and Washington to enable offshore wind integration combined with land-based wind expansion predominantly in Idaho (additional transfer paths)<br>- New 500-kV overlays from 230-kV between NorthernGrid-East and WestConnect (Montana – Wyoming and Idaho – Wyoming) |
| Western Interconnection | WestConnect | - In addition to Colorado Power Pathway projects (345-kV), further 345-kV additions (east-west) increasing transfer capabilities between Colorado and Utah<br>- 345-kV strengthening between WestConnect-North and WestConnect-South (four-corners) as additional paths for predominantly Wyoming and Colorado wind capacity<br>- Extensive 500-kV strengthening (single-circuit to double-circuit) in WestConnect-South predominantly enabling moving solar PV and wind capacity from New Mexico and Arizona to California<br>- Several 500-kV overlays of existing 345-kV networks in WestConnect-South (New Mexico and Arizona) playing a similar role as 500-kV strengthening (moving wind and solar PV capacity east-west to load centers in Arizona and California) |
| ERCOT | ERCOT | - Unchanged from Limited |

[1] *Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).*

[2] *SERTP/SCRTP.*

Table B-5. Rationale for Nodal Transmission Portfolios (MT-HVDC scenario)

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| Eastern Interconnection | FRCC | - 2- x 4-GW bipoles: one FRCC and Southeast and one between FRCC-MISO (South) used for bidirectional power transfers of solar PV (and some wind from nonadjacent regions including MISO and SPP)<br>- Localized 230-kV strengthening in northern, central, and southern parts of Florida integrating large amounts of solar PV capacity<br>- Single-circuit to double-circuit 500-kV expansion between FRCC and Southeast (Florida – Georgia) |
| Eastern Interconnection | ISONE | - N/A (other than already prescribed transmission expansion) |
| Eastern Interconnection | MISO | - 2- x 4-GW bipole from northern part of MISO into PJM-West to bring wind capacity from extreme northern (Montana) and central parts (Minnesota) of MISO-North to load centers in PJM-West |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | - Northern parts of MISO-North require some strengthening of existing 230-kV and 345-kV networks to collect wind capacity for HVDC transfers<br>- Additional 2- x 4-GW bipoles (multiterminal) from central parts of MISO-North into PJM-West and MISO-Central for moving power across MISO and toward PJM-West<br>- Combination of some new double-circuit 345-kV west-east and strengthening of existing paths to support further movement of wind capacity in MISO-North toward PJM-West and MISO-Central<br>- MISO-Central requires additional single-circuit to double-circuit strengthening (Missouri, Indiana, Illinois, Michigan)<br>- Only selected parts of the existing 765-kV networks between MISO and PJM require single-circuit to double-circuit strengthening to enable transfers between HVDC terminals in MISO and PJM<br>- 4- x 4-GW multiterminal HVDC links in MISO-South enable linking between SPP-South, MISO-South, and the Southeast region<br>- 1- x 4-GW HVDC links with ERCOT for exports predominantly of wind and solar PV from ERCOT |
| Eastern Interconnection | NYISO | - 2-GW monopole between upstate NYISO and PJM increasing exchange capacity between NYISO and PJM<br>- Strengthening of 345-kV east-west transfer capacity across NYISO (upstate) enabling exports from 2-GW bipole<br>- Additional 500-kV strengthening between PJM-West and NYISO (link into existing 345-kV networks in NYISO) |
| Eastern Interconnection | PJM | - 4- x 4-GW PJM-West – PJM-East, MISO-Central – PJM-East, PJM-East – Southeast link interregionally between MISO, Southeast, and NYISO, predominantly to move wind capacity from MISO (and indirectly from SPP) into PJM<br>- Selected expansion of the existing 765-kV networks enables exports from HVDC terminals, transfers to embedded HVDC terminals, and improved contingency performance in the footprint<br>- New 500-kV overlay as in AC and Limited to integrated offshore wind capacity<br>- Several interregional 500-kV strengthening needs along Eastern Seaboard and between PJM-East and Southeast |
| Eastern Interconnection | Southeast[2] | - 4-GW bipole linking PJM-East and Southeast to support the combination of large amounts of wind and solar from the Southeast to PJM<br>- 4-GW bipole moving bidirectional power between MISO-Central and the Southeast leveraging wind in MISO and solar PV in the Southeast<br>- 4-GW bipole between the Southeast and SPP-South moving large amounts of wind into the Southeast<br>- Several supporting 500-kV strengthening in Tennessee, Georgia, Alabama, and Mississippi enabling embedded HVDC imports into the Southeast and exports to MISO-Central and PJM-East |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| Eastern Interconnection | SPP | - 2- x 4-GW bipoles between SPP and PJM-West moving large amounts of wind into strong areas of the existing 765-kV and 500-kV networks<br>- 2- x 4-GW multiterminal bipoles moving power north to south within SPP and enabling further transfers from SPP to MISO-Central and the Southeast<br>- 5- x 4-GW and 1- x 2-GW seam-crossing bipoles across several locations in SPP to move power between the Eastern Interconnection and Western Interconnection—four of these with WestConnect and one with NorthernGrid<br>- WestConnect-South and SPP-South HVDC comprises the starting point of meshed HVDC expansions between the Eastern Interconnection and Western Interconnection<br>- 2- x 4-GW seam-crossing HVDC bipoles between SPP-South and ERCOT mostly for bidirectional exchange of complementary wind capacity in ERCOT and SPP-South<br>- New 500-kV overlay west-east in SPP-South enabling improved contingency performance of extensive HVDC expansion in SPP-South and further transfer capacity for wind and solar PV in Oklahoma and Texas panhandle to MISO-South<br>- Several supporting single-circuit to double-circuit 345-kV expansions in SPP (South) to integrate large wind and solar PV capacity as well as improve contingency performance of HVDC expansions |
| Western Interconnection | CAISO | - 2- x 4-GW HVDC bipoles between CAISO-South and WestConnect-South shifting large amounts of solar PV and wind from Arizona and New Mexico toward California<br>- Similar new 500-KV expansions in CAISO-North for integration of offshore wind as in AC and Limited<br>- The strengthening of existing 500-kV between CAISO-North and CAISO-South enables further increased transfers |
| Western Interconnection | NorthernGrid | - 1- x 2-GW seam-crossing link between NorthernGrid-East and SPP-North<br>- Single-circuit to double-circuit 500-kV strengthening in NorthernGrid-East and NorthernGrid-West enables similar transfers of wind capacity from Wyoming toward Oregon and Washington<br>- Offshore wind is integrated in Oregon in a similar manner to that of the AC and Limited scenarios |
| Western Interconnection | WestConnect | - 2- x 4-GW seam-crossing capacity between ERCOT and WestConnect-South as well as 4-GW bipole between Arizona and New Mexico enables the combination of New Mexico and Texas wind and solar PV capacity to be sent toward load centers in Arizona and California<br>- 4- x 4-GW meshed HVDC seam-crossing expansion between WestConnect-South and SPP-South enables a large component of wind and solar capacity between the Eastern Interconnection and Western Interconnection<br>- 2- x 4-GW seam-crossing capacity expansion between WestConnect-North and SPP-North provides for the |

| Interconnect | Transmission Planning Region[1] | Summary |
|---|---|---|
| | | remainder of the dominant transfer capability between the Eastern Interconnection and Western Interconnection<br>- Two additional 4-GW HVDC links in WestConnect-North move Wyoming wind toward Colorado and across the seam-crossing HVDC links between WestConnect-North and SPP-North<br>- 4-GW bipole as seam-crossing capacity from WestConnect (New Mexico) to the southernmost parts of SPP<br>- 4-GW bipole moving power within WestConnect toward Colorado and enabling of seam-crossing between WestConnect and SPP-South<br>- Extensive strengthening of the existing 345-kV and 500-kV networks in WestConnect-South predominantly in New Mexico and Arizona support the multiterminal HVDC links between WestConnect, CAISO, and ERCOT<br>- New 500-kV overlay (from 345-kV) and new 500-kV paths between Arizona and New Mexico further supporting HVDC transfers and collection of wind/solar PV capacity |
| ERCOT | ERCOT | - 2- x 4-GW seam-crossing HVDC bipoles between ERCOT and the Western Interconnection (WestConnect) predominantly moving large amounts of wind and solar power from ERCOT to WestConnect; this supports exports from West Texas and hence a decreased need for 345-kV strengthening or new 345-kV paths<br>- 2- x 4-GW seam-crossing HVDC bipole between ERCOT and MISO-South getting wind from ERCOT into the Eastern Interconnection<br>- 2- x 4-GW seam-crossing HVDC bipole between ERCOT and SPP-South similarly getting wind and solar PV capacity from ERCOT into the Eastern Interconnection<br>- Existing 345-kV strengthening (single-circuit to double-circuit) is concentrated between Dallas-Fort Worth and Houston (north-south) with selected new paths needed and enabled by new double-circuit 345-kV expansions |

[1] *Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).*

[2] *SERTP/SCRTP.*

## B.5 Further Detailed Results for Earlier Scenarios

### Curtailment results in the Western Interconnection

Earlier scenarios (Section 4) used curtailment as a key stopping criteria metric during evaluation of the nodal translations. Figure B-6 compares aggregate curtailment numbers from the three scenarios. Curtailment peaks in the second quarter of the year, corresponding to the hydro runoff in the west, which is also a period of relatively low demand.

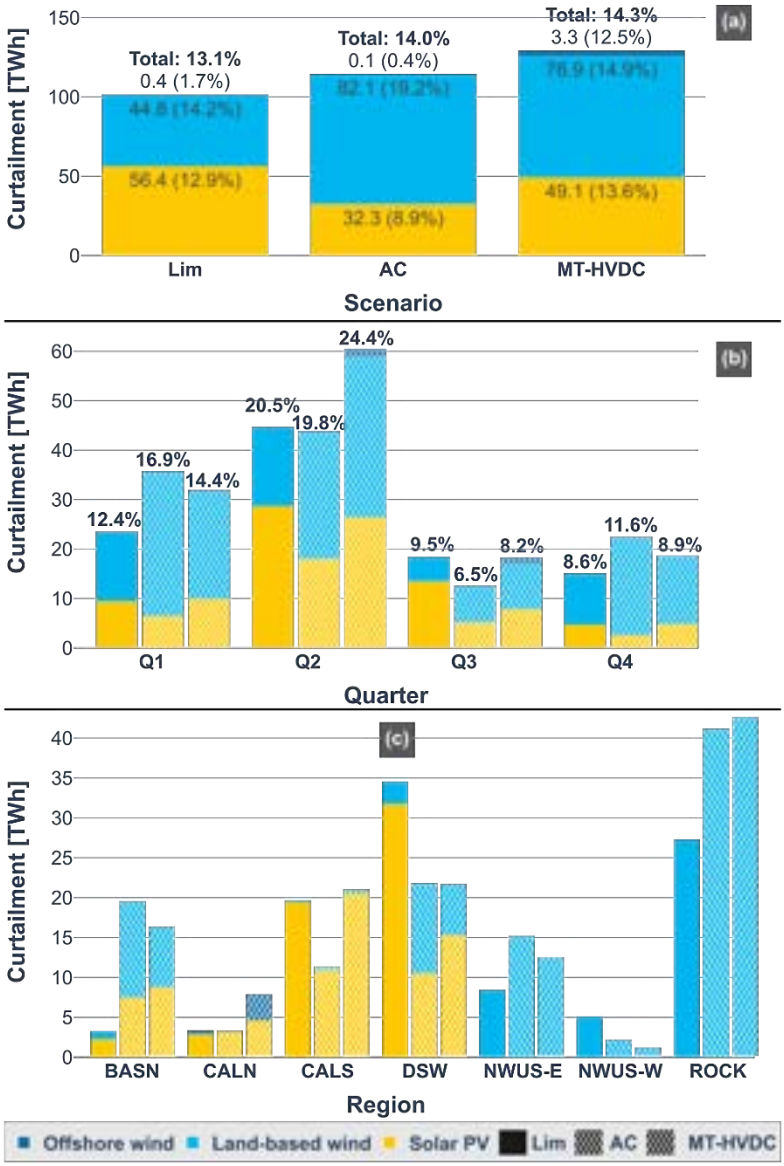



Figure B-6. Curtailment comparison between scenarios in the Western Interconnection

*Each panel represents a different level of spatial or temporal aggregation: (a) total curtailment, (b) curtailment by quarter, (c) curtailment by region.*

Figure B-7 shows the average weekday curtailment along with standard deviation for the three scenarios. Solar curtailment exhibits a high standard deviation over time because of seasonality or other weather events whereas wind is more consistent on average. As the share of wind increases in the interregional scenarios, it begins to exhibit more of the midday curtailment peak of solar.

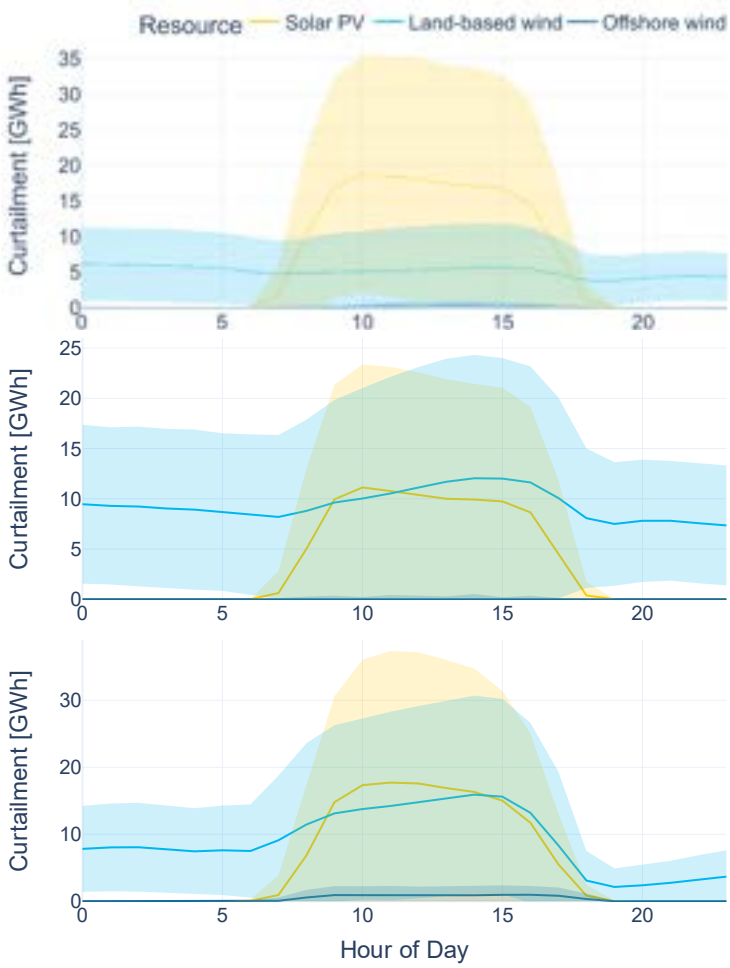



Figure B-7. Relationship between solar and wind curtailment in the Western Interconnection

*Average weekday trends shown as lines with standard deviation shaded: Limited (top), AC scenario (middle), MT-HVDC scenario (bottom).*

## MT-HVDC scenario results for the combined Western and Eastern Interconnections

Figure B-8 shows installed capacity post-nodal disaggregation for the complete MT-HVDC scenario on the combined Western and Eastern Interconnection footprint. Figure B-9 shows the resulting transmission expansion. The HVDC system is divided into several section as described in Appendix A.10.

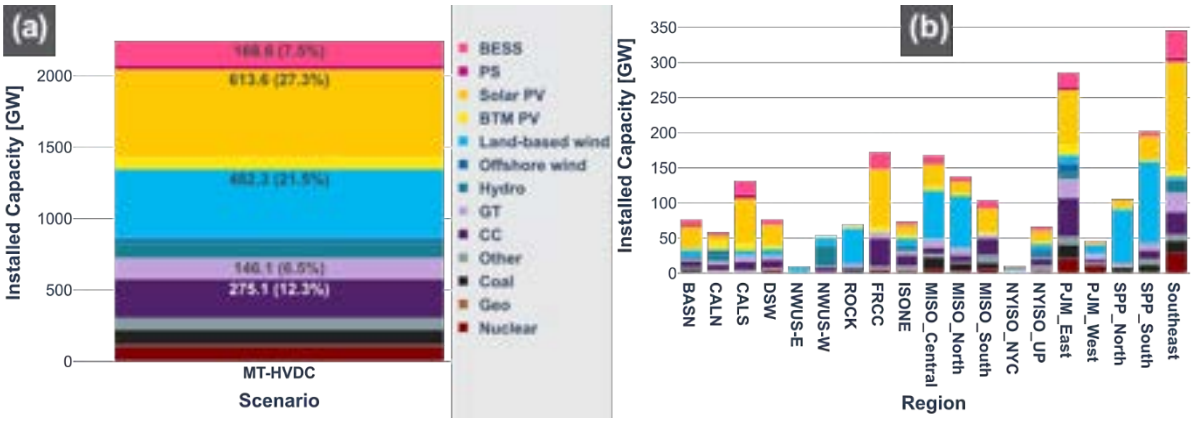



Figure B-8. Nodal disaggregated installed capacity for Western Interconnection and Eastern Interconnection

*Total installed capacity is shown in (a); (b) shows installed capacity by subregion.*

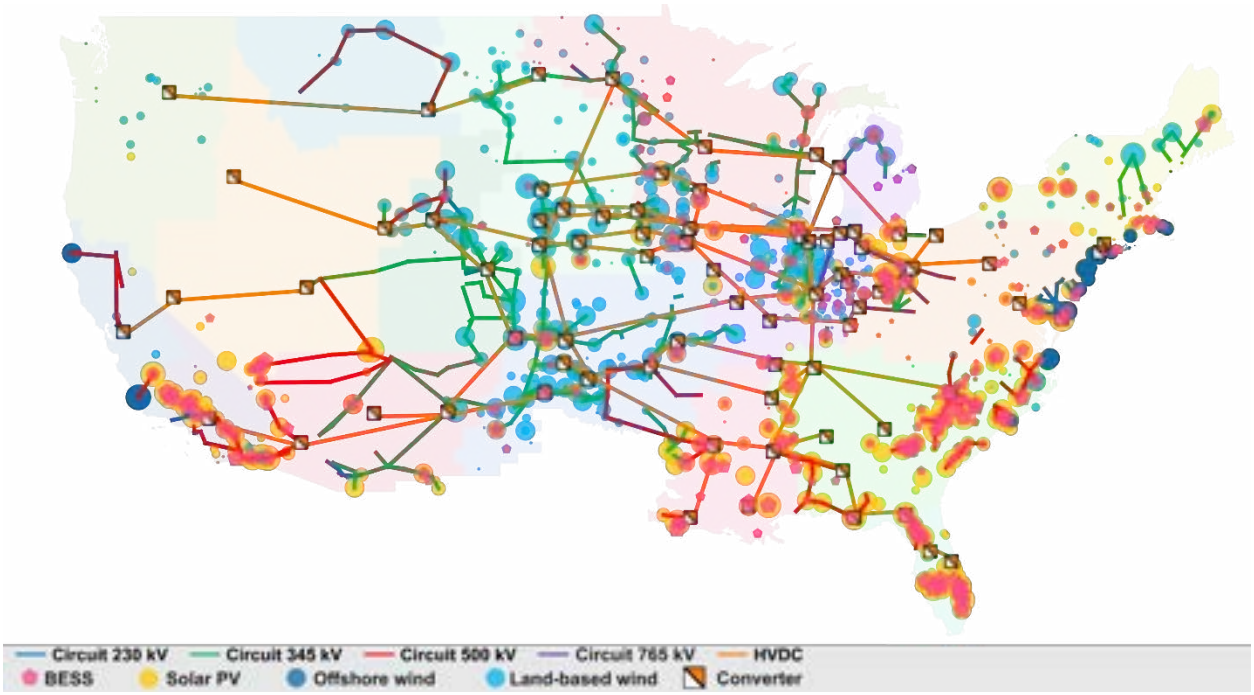



Figure B-9. Transmission expansion for MT-HVDC scenario for Western and Eastern Interconnection

The generation dispatch for the complete MT-HVDC scenario is shown in Figure B-10 aggregated over the combined Western and Eastern Interconnection footprint for the whole year and quarterly as well as split up by subregion. Except for the central section of MISO, the regional breakdown highlights wind generation is using the MT-HVDC network to get to load. The central section of MISO lies in the path of many HVDC connections to the hub around Chicago, Illinois. Some of the converter stations around this hub are placed in the MISO footprint and the power continues to Chicago on the AC system. This helps explain the opposite direction of DC and AC imports in the bottom of Figure B-10 for MISO Central.

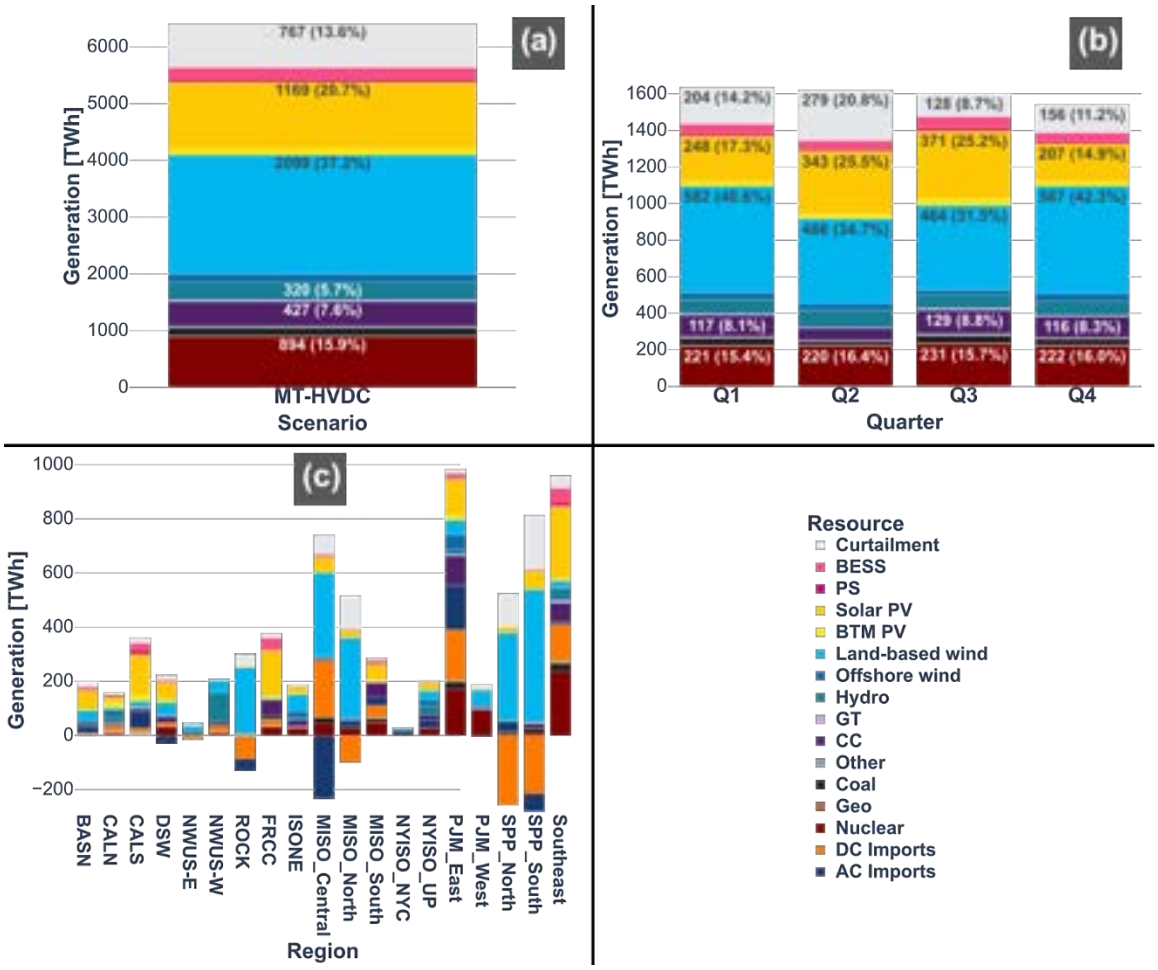



Figure B-10. Generation dispatch for combined Western Interconnection and Eastern Interconnection

*Panel (a) shows totals, (b) shows by quarter, and (c) shows by region.*

Curtailment in the complete MT-HVDC scenario is shown in Figure B-11. The distribution in terms of resource type skews much more heavily toward wind compared to the Western Interconnection alone and is concentrated in the central regions of the country (SPP and MISO).

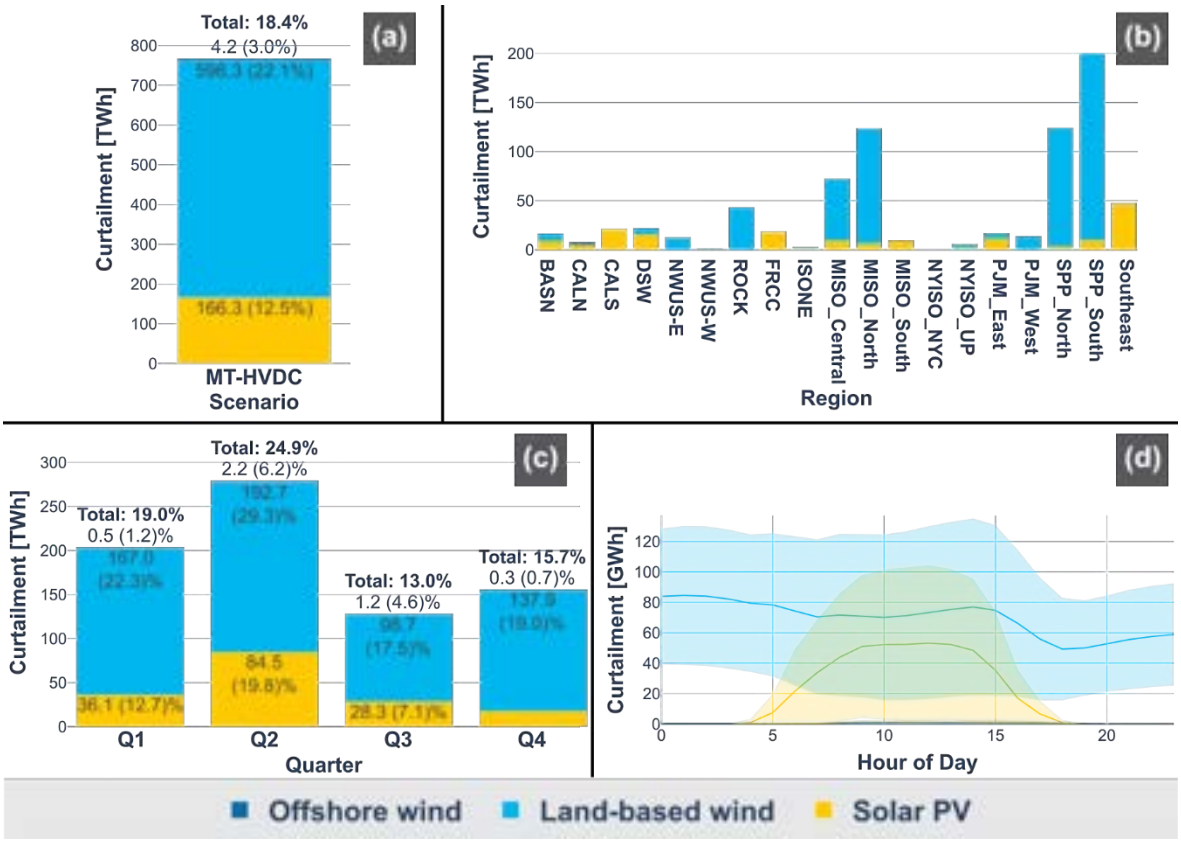



Figure B-11. Curtailment for combined Western Interconnection and Eastern Interconnection footprint

*Panel (a) shows aggregate curtailment, (b) shows aggregate curtailment by subregion, (c) shows aggregate curtailment by quarter, and (d) shows average weekday trends as lines with ±1 standard deviation shaded.*

The use of all HVDC corridors in both the Western Interconnection and Eastern Interconnection are shown along with their geographic location in Figure B-12 and Figure B-13. Except for the SPP north-south link and the FRCC to Southeast link, the flows in the east are predominantly one-sided, showing a movement from the resource-rich western portion to the load areas in the east. This pattern contrasts with the use of HVDC in the Western Interconnection, where flows—especially along the southern border—are more bidirectional.

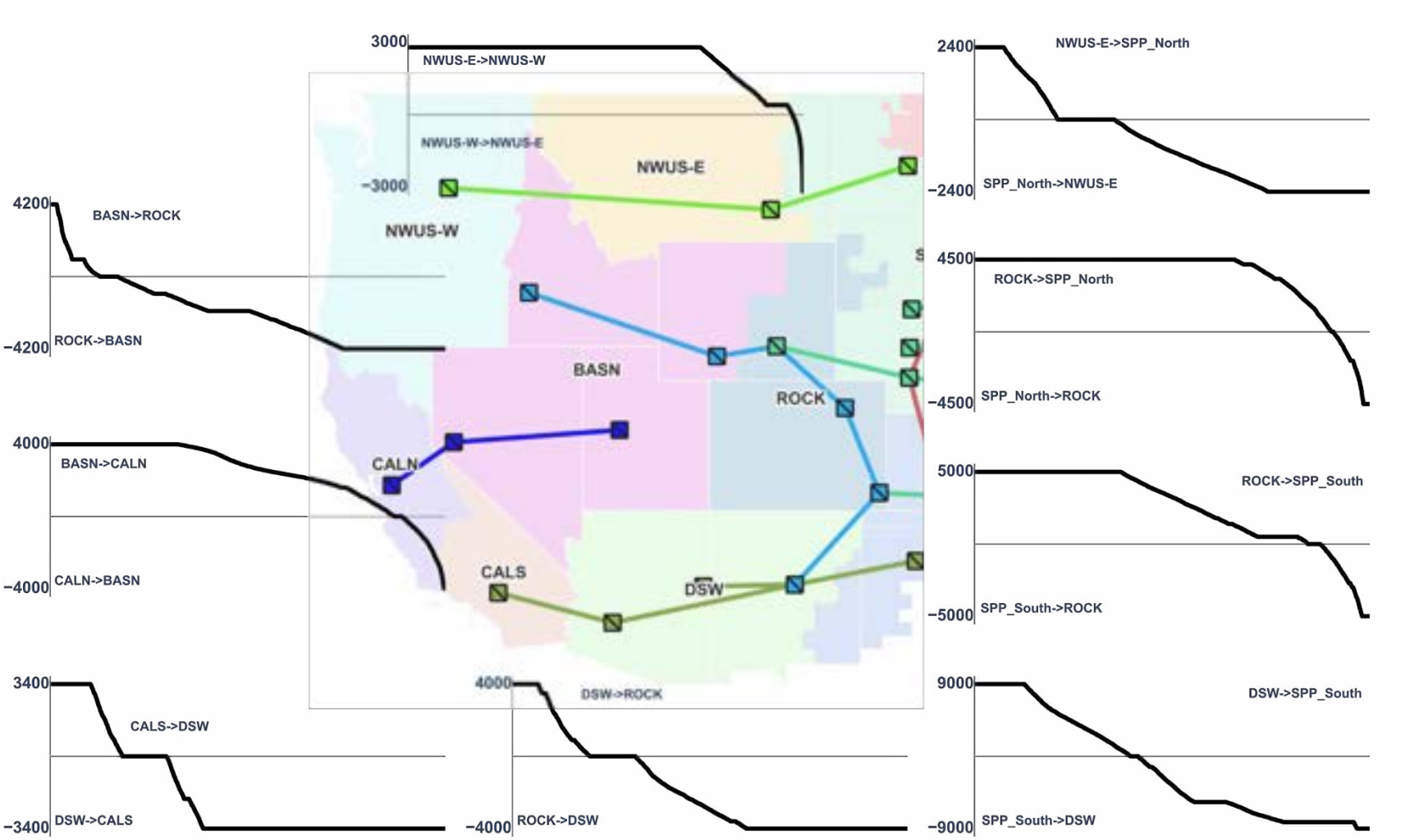



Figure B-12. Use of HVDC interregional interfaces in the MT-HVDC scenario (Western Interconnection)

*Flow duration curves show the aggregate flow on the MT-HVDC lines between the subregions (including seam flows to the Eastern Interconnection).*

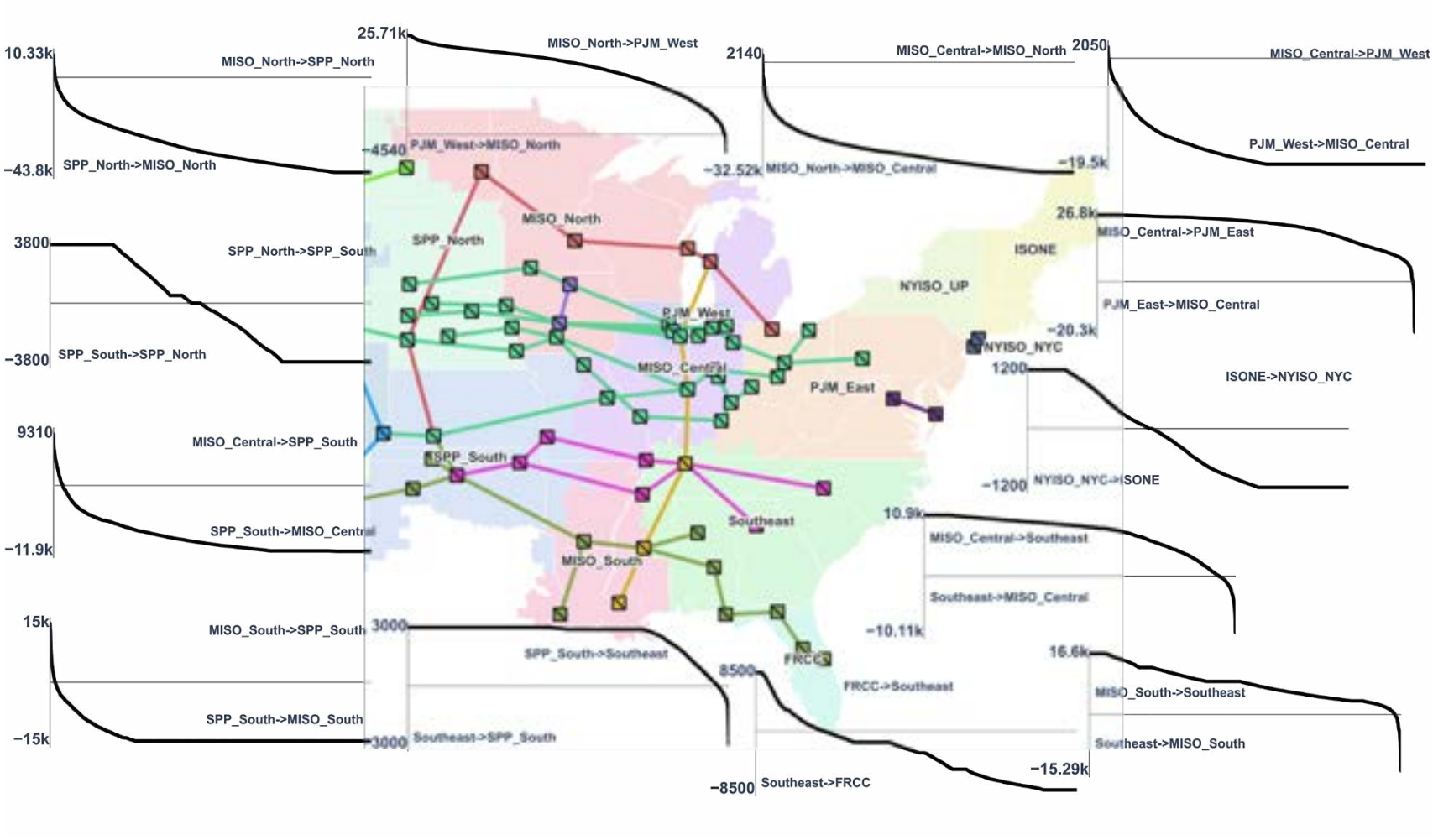



Figure B-13. Use of HVDC interregional interfaces in the MT-HVDC scenario (Eastern Interconnection)

*Flow duration curves show the aggregate flow on the MT-HVDC lines between the subregions. Note the HVDC links in PJM do not cross subregion boundaries and are therefore not shown.*

# Appendix C. Tools

## C.1 Sienna Modeling Framework

Production cost models simulate the least-cost optimal scheduling of electric generation to meet system demand and transmission constraints. The functionality provided by the Sienna modeling framework was used as the production-cost simulation engine in the National Transmission Planning Study (NTP Study) (National Renewable Energy Laboratory [NREL] 2024; Lara et al. 2021). The choice of the Sienna modeling framework was a result of the range of libraries that make up Sienna being capable of efficient and reproducible data management, programmatic access (which enables reproducibility and dataset maintenance), and efficient storage and access to support large-scale modeling, validation, and change management (all enabled through the libraries part of Sienna\Data). Nodal production cost modeling in Sienna (via Sienna\Ops) is transparent, programmatic, and scalable, which enables validation and verification as well as the potential to develop further modeling functionality extensions. Based in Julia (Bezanson et al. 2017), the Sienna framework enables speed of development and execution combined with a wide range of available libraries while leveraging the JuMP modeling language embedded in Julia for optimization (Lubin et al. 2023).

## C.2 Grid Analysis and Visualization Interface

The Grid Analysis and Visualization Interface is a web application prototype for visualizing large nodal bulk grid power simulations and is available at http://github.com/NREL/GRAVI. It has been developed primarily as part of the NTP Study with three main objectives:

- Aid in the dissemination of detailed nodal-level modeling results to stakeholders
- Visualize and interpret large-scale and data-intensive modeling results of the contiguous U.S. bulk power system
- Aid in the transmission expansion planning that forms part of the translation of zonal models into nodal models.

The tool provides a dynamic geospatial animated visualization of each timestep from a simulation run along with complementary dynamic subplots. A screenshot of this for a contiguous United States (CONUS)-wide nodal production cost model outcome is shown in Figure C-1. It provides two controllable geospatial layers: one for bulk power generation and the other for transmission use and flow.

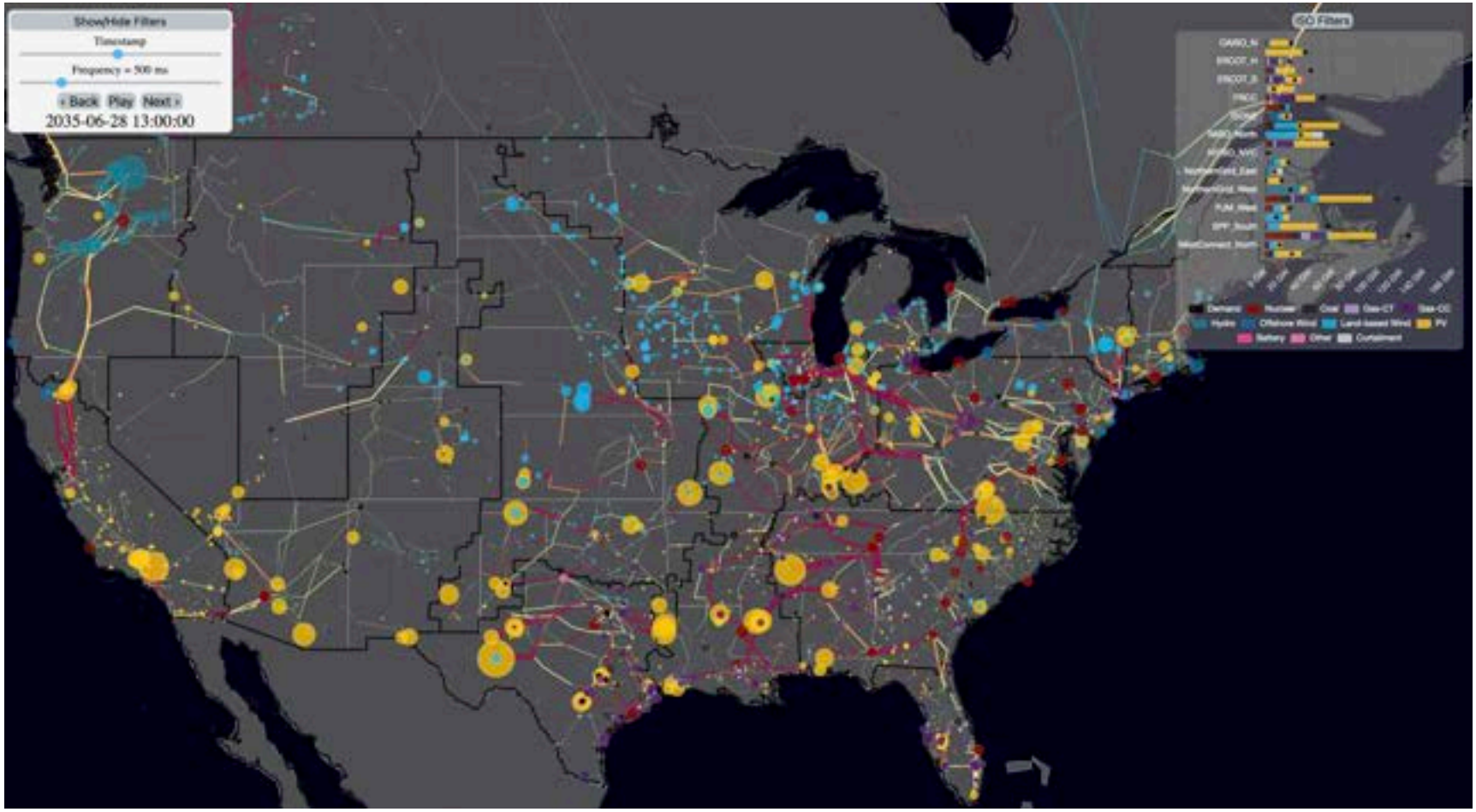



Figure C-1. Screenshot-generated custom tool developed for the NTP Study (Grid Analysis and Visualization Interface)

# Appendix D. Economic Methodology

## D.1 Transmission Capital Cost Methodology

Transmission costs for the Limited Alternating Current (AC) Western Interconnection case and the Interregional AC Western Interconnection case were developed based on the transmission lines added to the GridView Production Cost Model by voltage class (230 kilovolt [kV], 345 kV, and 500 kV). The Western Electricity Coordinating Council (WECC) Transmission Calculator (Black & Veatch 2019) updated by E3 in 2019 (E3 2019) was the basis for calculating the capital costs for transmission. The WECC Calculator multipliers for land ownership and terrain were used to estimate the cost of added transmission. The WECC Environmental Viewer was used to calculate costs for rights of way (ROWs), terrain, and land class. This appendix provides details on how the ROW costs and terrain type multipliers were used to estimate the transmission capital cost.

## D.2 Developing the Right-of-Way Costs

Geospatial data for landcover, risk class, and Bureau of Land Management (BLM) zone designation were acquired from the WECC Environmental Viewer (ICF, n.d.) (see Figure D-1). The percent and total mileage of all transmission lines for each case intersecting land cover types and BLM category were estimated using the ArcMap Pro Tabulate Intersection Tool[68] (see Figure D-2 and Figure D-3). BLM land zones and their costs are provided in Figure D-1. Land cover cost is estimated by the total mileage multiplied by ROW width multiplied by BLM rental cost per acre (Table D-1). The ROW width required by transmission lines by voltage class was acquired from Duke Energy Transmission Guidelines (Table D-2) (Duke Energy, n.d.).

[68] ArcGIS Pro. No date. “Tabulate Intersection Analysis.” Available at https://pro.arcgis.com/en/pro-app/latest/tool-reference/analysis/tabulate-intersection.htm

Figure D-1. WECC environmental data viewer

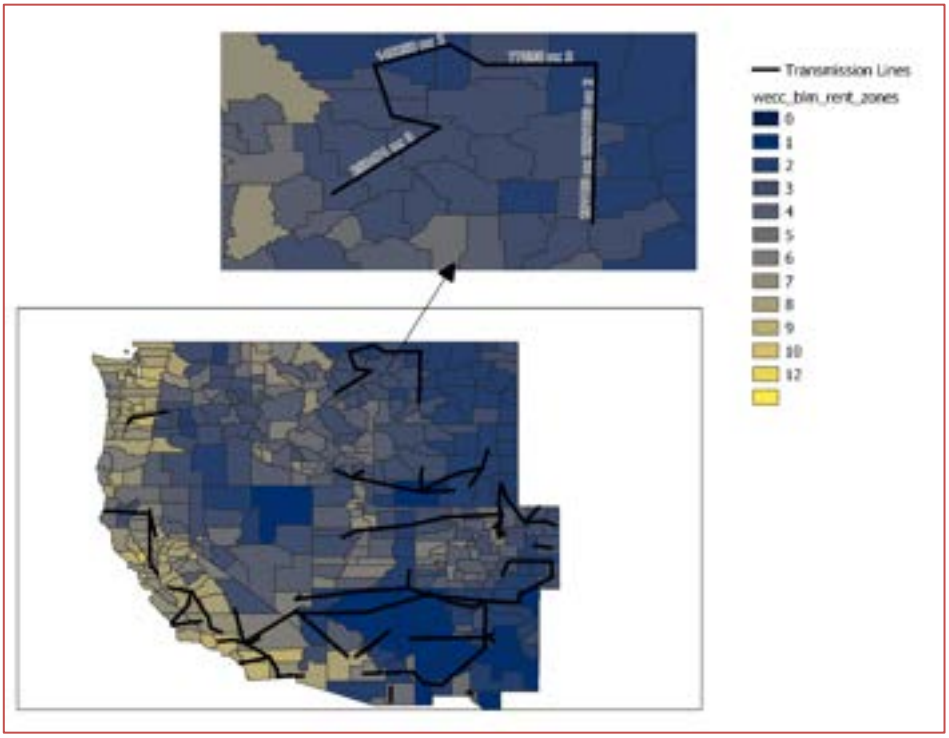



Figure D-2. BLM zone classes and transmission lines for Interregional AC Western Interconnection case

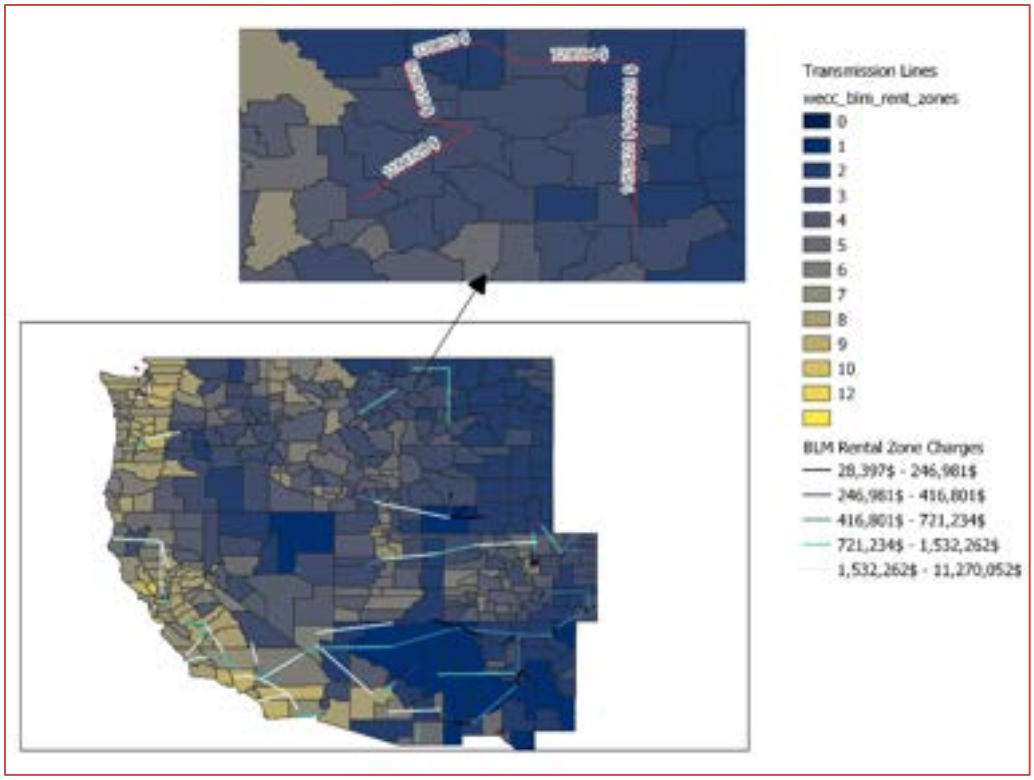



Figure D-3. Costs associated with respective BLM zone

Table D-1. BLM Cost per Acre by Zone Number

| BLM Cost Zone Number | $/Acre |
|---|---|
| 1 | $83 |
| 2 | $161 |
| 3 | $314 |
| 4 | $474 |
| 5 | $653 |
| 6 | $942 |
| 7 | $1,318 |
| 8 | $838 |
| 9 | $4,520 |
| 10 | $13,882 |
| 11 | $27,765 |
| 12 | $69,412 |
| 13 | $138,824 |
| 14 | $208,235 |
| 15 | $277,647 |

Table D-2. Required Width for Transmission Lines by Voltage Class

| Voltage Class (kV) | Min Required Width (ft) | Max Required Width |
|---|---|---|
| 44–115 | 68 | 100 |
| 230 | 125 | 150 |
| 500–525 | 180 | 200 |

## D.3 Estimating the Cost by Terrain Type

Cost by land cover and terrain type was estimated as a multiplier (Table D-3) times the cost per mile by voltage class (Table D-4). Voltage classes included single-circuit and double-circuit additions. The cost by mile assumes the conductor type is aluminum conductor steel reinforced (ACSR).

Table D-3. Land Cover and Terrain Classification Categories With Multiplier

| Terrain Type | Terrain Type Identifier | Multiplier |
|---|---|---|
| Forested | 1 | 2.25 |
| Scrubbed/Flat | 2 | 1 |
| Wetland | 3 | 1.2 |
| Farmland | 4 | 1 |
| Desert/Barren Land | 5 | 1.05 |
| Urban | 6 | 1.59 |
| Rolling Hills (2%–8% slope) | 7 | 1.4 |
| Mountain (>8% slope) | 8 | 1.75 |

Table D-4. Cost per Mile by Voltage Class

| Voltage Class | Cost per Mile |
|---|---|
| 230-kV Single Circuit | $1,024,335 |
| 230-kV Double Circuit | $1,639,820 |
| 345-kV Single Circuit | $1,434,290 |
| 345-kV Double Circuit | $2,295,085 |
| 500-kV Single Circuit | $2,048,670 |
| 500-kV Double Circuit | $3,278,535 |

## D.4 Summary of Selected Literature Estimating the Economic Benefits of Transmission

Building interregional transmission in the United States requires cooperation across multiple balancing authorities and independent system operators (ISOs). Estimating the economic benefits of interregional transmission provides critical information that could help enable this cooperation. This section describes some of the issues highlighted in previous literature regarding estimation of the economic benefits of transmission.

Transmission investment has generally been lower than the socially optimum amount. William Hogan (1992), J. Bushnell and Stoft (1996), and J. B. Bushnell and Stoft (1997) have shown transmission investments that are profitable to private ownership are also economically efficient from a system perspective. However, many investments that are socially beneficial are not profitable for privately owned transmission (Doorman and Frøystad 2013; Egerer, Kunz and von Hirschhausen, Christian 2012; Gerbaulet and Weber 2018). The primary reason is transmission enables lower-cost generation, providing benefits to the system (and end consumers) that transmission owners do not receive and hence is not used in their decision making. Several studies have shown bargaining among utilities, ISOs, and so on will often not lead to an economically efficient amount of transmission and these issues are amplified when market distortions such as market power and higher negotiation costs are present (Cramton 1991; Anderlini and Felli 2006; Joskow and Tirole 2005).

William Hogan (2018) has written the most detailed methodology for the estimation and computation of transmission projects. His methodology draws on the vast literature on the economics of trade. A transmission can be modeled similar to a policy change that opens up trade between two nations/states/and so on that was previously closed. Trade economics is often taught from the perspective of comparative advantage, where both nations specialize in some product and specialization occurs with trade—benefiting both nations. With transmission, there is only one good available for trade. The region with lower-cost generation will be an exporter, and the region with higher-cost generation will be the importer. This can be modeled with the standard economic framework where generators are suppliers, utilities are the consumers, and the payments made for transmission are modeled similar to ad valorem taxes. Using this framework, producer benefits can be measured with producer surplus, consumer benefits can be measured with consumer surplus, and the payments to transmission owners are considered "transmission rents." Transmission rents are considered similar to ad valorem taxes where the revenue is a transfer to another entity—that is, transmission rents should not be considered losses, but the "wedge" the rents place between supply and demand does create deadweight loss.

Several studies have considered similar transmission expansion needs in the European Union (Sanchis et al. 2015; Neuhoff, Boyd, and Glachant 2012; Kristiansen et al. 2018). Olmos, Rivier, and Perez-Arriaga (2018) showed a potential North Sea transmission project joining six northern European countries could have net benefits up to €25.3 billion.

Within the United States, there have been limited national studies (Pfeifenberger, n.d.; Stenclik, Derek and Deyoe, Ryan 2022). Some studies estimate the benefits of intraregional transmission including in Midcontinent System Operator (MISO), California Independent System Operator (CAISO), and New York Independent System Operator (NYISO) (Gramlich, Rob 2022; Chowdhury and Le 2009; Conlon, Waite, and Modi 2019). These studies focus on estimating the benefits at the system level; i.e., they do not consider the benefits that accrue to consumers, producers, or transmission owners separately. The system benefits are computed by taking the reduction in generation costs within each region and adjusting by subtracting import payments and adding export revenues. William Hogan (2018) and CAISO (2017) showed the "system" method yields the same total regional benefit when the benefits to consumers, producers, and transmission rents are combined. However, the methods are equivalent only under the assumption demand is fixed at each location.

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# National Transmission Planning Study

## Chapter 4:

# AC Power Flow Analysis for 2035 Scenarios

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

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U.S. Department of Energy, Grid Deployment Office. 2024. *The National Transmission Planning Study*. Washington, D.C.: U.S. Department of Energy. https://www.energy.gov/gdo/national-transmission-planning-study.

# Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios (this chapter)** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# List of Acronyms

| | |
|---|---|
| AC | alternating current |
| ADS | Anchor Dataset |
| API | application programming interface |
| BA | balancing authority |
| BESS | battery energy storage systems |
| BTM | behind the meter |
| CAISO | California Independent System Operator |
| C-PAGE | Chronological AC Power Flow Automated Generation |
| CDF | cumulative distribution function |
| DC | direct current |
| DOE | U.S. Department of Energy |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| GDAL | Geospatial Data Abstraction Library |
| GIS | geographical information system |
| GW | gigawatt |
| HVDC | high-voltage direct current |
| ID | identification |
| IDW | inverse distance weighting |
| ISO | independent system operator |
| km | kilometer |
| KS | Kolmogorov–Smirnov |
| KS-D | Kolmogorov–Smirnov distance |
| kV | kilovolt |

| | |
|---|---|
| LHSD | Latin hypercube sampling with dependence |
| MW | megawatt |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| PCM | production cost model |
| PNNL | Pacific Northwest National Laboratory |
| PSLF | Positive Sequence Load Flow |
| PSS/E | Power System Simulator for Engineering |
| PV | photovoltaic |
| ST | steam turbine |
| TRC | technical review committee |
| VRE | variable renewable energy |
| WECC | Western Electricity Coordinating Council |

# Chapter 4 Overview

This chapter presents the National Transmission Planning Study (NTP Study) alternating current (AC) power flow analysis methods and key findings, in line with key NTP Study goals to identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. Power flow studies are vital for determining how best to operate current transmission systems and plan for system expansion.

This chapter evaluates the reliability of transmission expansion options using power flow analyses of two specific transmission expansion scenarios that were developed for the Western Interconnection in support of the NTP Study: 1) the Western Interconnection 2035 Limited (Lim) scenario and 2) the Western Interconnection 2035 Alternating Current (AC) scenario.[2] The specific assumptions used for these scenarios are high demand growth[3] and the 90% decarbonization by 2035 emissions constraint. Though the NTP Study team used power flow software and methods accepted by industry transmission planners to conduct contingency analyses, the team's analysis neither simulated the full scope of contingencies that transmission planners customarily perform nor considered monitoring criteria or operating procedures specific to each utility. This chapter analyzes the most critical and impactful contingencies recognized by the transmission planning community to test the overall robustness of the transmission expansion scenarios and demonstrates the associated method of power flow case development, which can be adopted for further detailed reliability analyses.

### Key Findings

*Using tools refined in the NTP Study, power flow cases with different generation mixes can be extracted from production cost model simulations.*

Intelligent sampling methods, such as those applied in this chapter, should be used to select representative hours from the production cost model for the power flow analysis as planning engineers face significantly varying load, wind, solar, and online generation mixes within the same scenario. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.

*Power grids with large transmission buildouts and clean energy penetration can be planned to withstand contingencies.*

New transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded. Utility-scale

[2] The power flow analysis study examined only the Lim and AC scenarios within the Western Interconnection footprint because of study timeline limitations. Future areas recommended for study include conducting additional stress analyses for combined Eastern and Western Interconnection scenarios expanding transmission scenarios (e.g., multiterminal high-voltage direct current [HVDC]).
[3] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

storage can play a key role in providing the primary frequency response for large power plant contingencies. However, a full reliability analysis is necessary for new grid infrastructure.

*Advanced data analytics developed in this study can help industry understand grid behavior for many AC power flow hourly snapshots and contingencies.*

The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies

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# 1 Introduction

This chapter describes the power flow analysis of two specific transmission expansion scenarios that were developed for the Western Interconnection in support of the NTP Study:**Error! Bookmark not defined.**

1. **Western Interconnection 2035 Limited (Lim) Scenario**
   Transmission is developed only within Federal Energy Regulatory Commission (FERC) Order No. 1000 planning regions; no interregional transmission is included.

2. **Western Interconnection 2035 Alternating Current (AC) Scenario**
   Transmission is developed between adjacent FERC Order No. 1000 regions in the Western Interconnection; no transmission is built between the Western and Eastern Interconnections.

The specific assumptions used for these scenarios are high demand growth[4] and a 90% decarbonization by 2035 emissions constraint. To reliably plan for a high penetration of wind and solar generation, grid planners perform steady-state voltage and thermal contingency analyses of numerous AC power flow models that bracket the range of the varying dispatch characteristics through all hours of the year.

The AC power flow models in this chapter are based on industry-provided data with significant additions of new wind, solar, and storage resources and transmission expansions based on capacity expansion modeling results (Chapter 2). The study team translated the capacity expansion model results, through zonal-to-nodal translation (Chapter 3), into a nodal production cost model. The production cost model simulations provided chronological hourly dispatch of generation and load. As described in this chapter, the study team fed this hourly dispatch from the production cost model into the AC power flow models to perform a steady-state contingency analysis.

Figure 1 summarizes how the power flow cases referenced in this chapter were created in relation to the initial datasets, capacity expansion modeling, and zonal-to-nodal realization found in other chapters. Grid planners can use this strong functional framework and the associated datasets to accelerate the analysis and development of new transmission.

[4] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, please refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

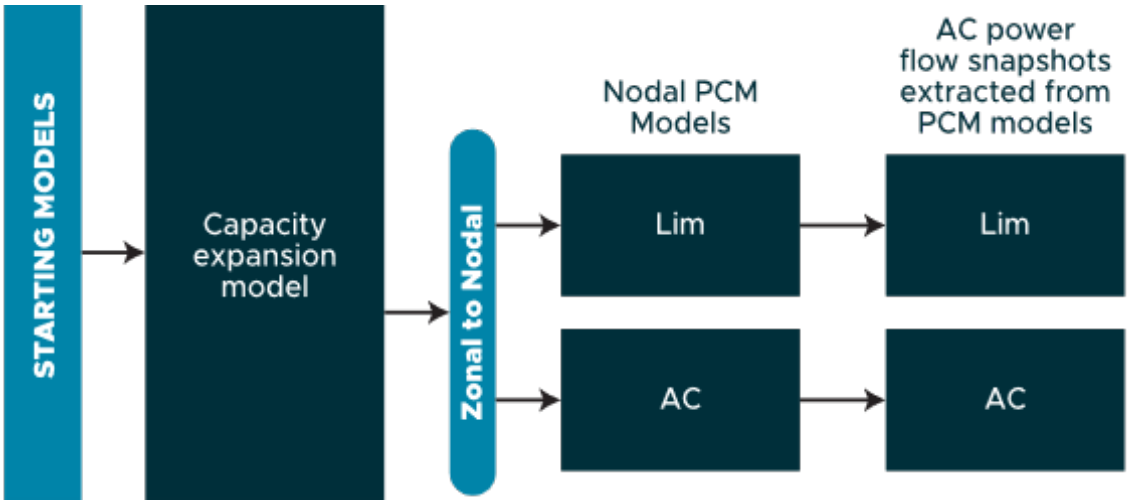



Figure 1. The NTP Study modeling framework consists of incorporating datasets and assumptions, performing capacity expansion modeling (Chapter 2), translating capacity expansion modeling results into nodal production cost modeling (Chapter 3), and conducting power flow modeling (this chapter)

*PCM = production cost model*

# 2 Methodology

This section provides a brief description of the methods used to create AC power flow cases from the production cost model. It conveys the evolution of the power flow from the production cost model, why it is necessary to advance the state of the art in power flow analytics, and the benefits that industry can gain from this analysis in the NTP Study to replicate the process for detailed transmission planning studies.

## 2.1 Importance of the Linkage Between the Production Cost Model and Power Flow Model

Grid planners need enhanced power grid reliability studies to prepare the transmission network for the increasing penetration of variable generation and the growing variability and volume of electric demand. Grid planning at the interconnection level currently requires only a small number of system snapshots to manage today's grid. As transmission expands, however, planners will need greater numbers of system snapshots for reliable grid planning, especially interregional transmission, as intricate transactions among balancing authorities (BAs) become more common and as variable renewable energy (VRE) penetration increases. Grid planners will need datasets, tools, and models that provide the ability to examine solutions across thousands of chronological power flow cases to understand the operational impacts of increased penetrations of VRE and changing load patterns (Hitachi ABB 2024; Western Electricity Coordinating Council [WECC] 2020a). Chronological power flow is valuable in transmission planning to calculate performance indices for systems with high renewables penetration, such as the optimal combination of network reinforcements to reduce energy spillage and the cost-effectiveness of equipment investments (WECC 2020b).

The process to create a single, operable AC power flow model takes a substantial amount of time because it involves production cost modeling, convergence of the AC power flow, and reactive power planning (da Silva et al. 2012; Hitachi ABB 2024; Independent System Operator [ISO] New England 2019; WECC 2020a, 2021). To address these challenges, the Pacific Northwest National Laboratory (PNNL) developed a chronological AC power flow automated generation (C-PAGE) tool (Vyakaranam et al. 2021) to bring system dispatch time series from the PCM into time-sequenced power flow runs for reliability analysis. The study team used C-PAGE to convert nodal PCM outputs to AC power flow cases for selected scenarios in this chapter.

## 2.2 Chronological AC Power Flow Automated Generation (C-PAGE)

The analysis in this chapter used the C-PAGE tool (Vyakaranam et al. 2021) to convert system dispatch time series from a PCM into time-sequenced power flow runs for a reliability study. C-PAGE includes procedures for translating datasets between production cost models and power flow models, creating chronological AC power flow instances and automating the process with choices for delivering results in a variety of formats. The study team used C-PAGE to generate AC power flow cases. Figure 2 depicts the three-stage C-PAGE procedure for preparing AC power flow cases. Each step is described in more detail next.

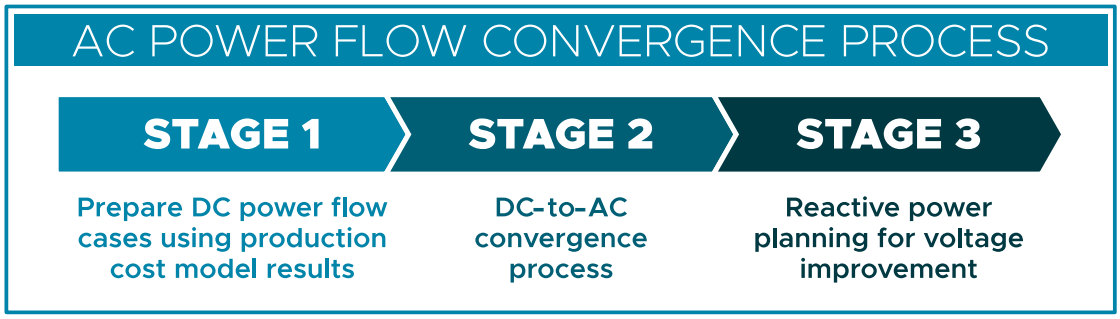



Figure 2. C-PAGE AC power flow three-stage convergence process

*DC = direct current*

### 2.2.1 Stage 1: Prepare the DC power flow cases using production cost model results

For C-PAGE to successfully prepare the DC power flow case using the PCM generation dispatch, the system topologies of the production cost model and power flow model must match. The PCM outputs consist of the load at the BA level along with load distribution factors to distribute loads at each node and generation aggregated at the power plant level. Figure 3 shows the process of disaggregating generation and load from the power plant and BA levels, respectively, to the nodal level for use in a power flow model. Appendix A presents detailed data mappings and validation of the production cost model and power flow model.

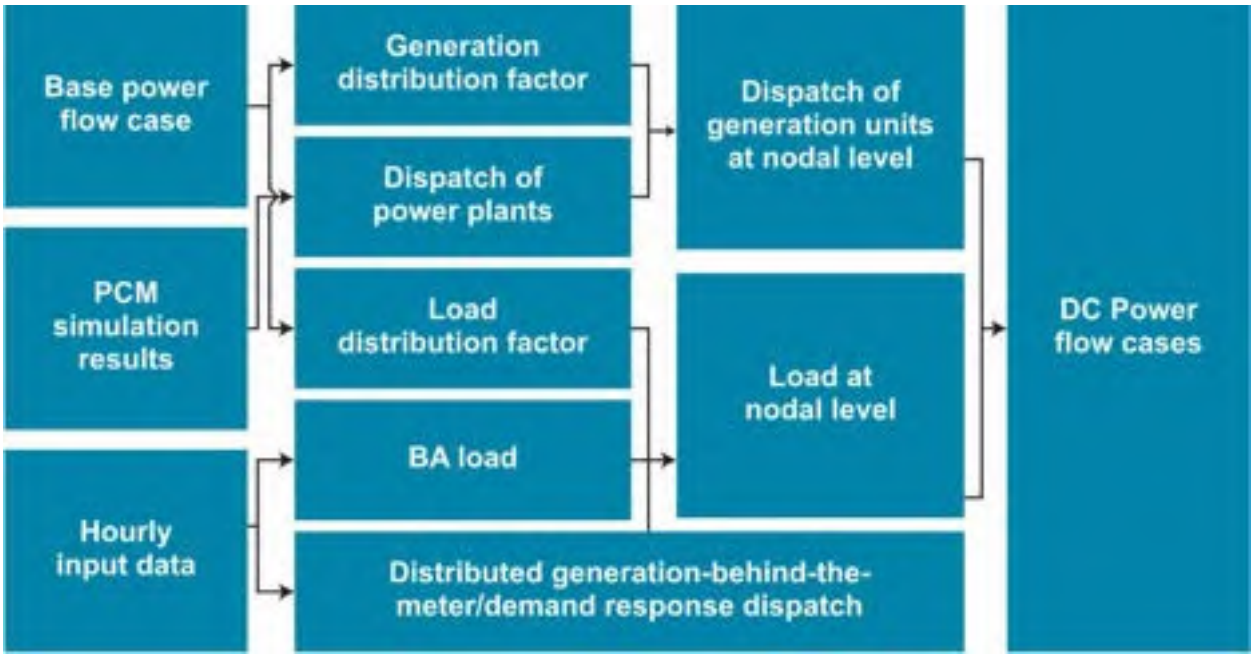



Figure 3. Process of disaggregating generation and load from production cost model simulation results to power flow cases

### 2.2.2 Stage 2: DC-to-AC convergence process

A production cost model uses a DC power flow, where transmission line losses are zero. Thus, the total generation in the resulting DC power flow case is equal to the total load, which is reflective of the forecasted substation load plus the estimated transmission line losses. However, the transmission line losses are inherently calculated in the AC power flow solution. Therefore, when converting the DC power flow case to an AC power flow case to ensure generation, load, and losses are equal, either nodal load reduction or increases in total generation are required to compensate for the transmission losses. In this chapter, the study team lowered the loads in C-PAGE to compensate for the losses to ensure the PCM generation outputs remain unchanged. Accordingly, in Step 2 of the procedure, the nodal loads must be iteratively reduced before an AC power flow solution is found. A detailed procedure for converting a converged DC power flow case from the production cost model results to a converged AC power flow case is presented in Appendix B.

### 2.2.3 Stage 3: Reactive power planning for voltage improvement

After achieving a converged AC power flow case, the priority shifts to improving the bus voltage profile. This is a crucial step because a good voltage profile at one timestep directly affects the possibility of achieving a converged AC power flow solution in subsequent timesteps. In this stage, C-PAGE scans all bus voltages to identify voltage violations and adjusts or adds local reactive devices to mitigate bus voltage violations. Appendix B presents a detailed reactive power planning procedure to improve the voltage profile. The final converged AC power flow case for the current timestep is the resulting power flow case after improving the voltage profile using existing and additional shunts.

## 2.3 Intelligent Sampling

As a result of the transitioning power grid, rather than using the traditional approach of assessing a select number of operating situations (usually based on engineering judgment and experience), grid planners should evaluate a variety of operating situations that are representative of most operating conditions in a year. However, the industry lacks a statistical method for determining the number of representative hourly power flow cases that represents the entire year. To address this, the study team developed an intelligent sampling approach for scenario reduction to find a small number of hourly cases that are statistically representative of the whole year appropriate for power flow analysis. The approach accounts for the seasonal and diurnal variability of renewable energy sources, using a hierarchical design followed by a slicing/Latin hypercube sampling method to select a statistically representative subset of hours.

### 2.3.1 Method for intelligent sampling of representative hours

Considering the substantial role of VRE in the planning scenarios, it is critical to account for the multi-timescale variability of renewable energy sources. To ensure the sampling results are statistically representative, the intelligent sampling method used a multiscale hierarchical sampling strategy, as depicted in Figure 4. This innovative approach builds

on the foundation laid by the flexible smart sampling framework introduced in Chen et al. (n.d.) and Sun et al. (2021, 2023), expanding its capabilities by explicitly incorporating crucial multi-timescale information embedded in VRE.

The first step in creating the intelligent sampling method is to create joint cumulative distribution functions (CDFs) of the generator profiles of each generator fuel type. To mitigate the complexity of the sampling problem and efficiently capture critical aspects of different power generation hourly profiles, the study team classified generation profiles by fuel type. Following that, with the assistance of hourly mean and standard deviation statistics for generation, this approach ensures a reduced dimension while preserving the key features of the original generation data. The study team employed the Kolmogorov–Smirnov (KS) test to examine the representativeness of the samples concerning statistical properties, particularly the marginal distributions. The study team measured the distance between the two distributions using the KS distance (KS-D). In addition, the study team performed a statistical test of the KS-D to ensure the difference between the sampled and original distributions is statistically significant. This approach ensures a lower dimension problem while keeping the key characteristics of the original generation data.

Next, the study team used a two-level hierarchical structure to capture the natural variability in VRE. To account for such natural variability, the framework of the method included seasonal and diurnal cycles that govern the generation production of VRE:

- The four meteorological seasons represent the seasonal cycle: winter (December, January, and February), spring (March, April, and May), summer (June, July, and August), and fall (September, October, and November). Solar generation production is the only generation affected by the diurnal cycle, which is determined by daylight availability, which is dependent on both season and location.
- Three categories comprise the diurnal cycle: daytime, transition, and nighttime. The study team used solar penetration as a criterion for categorizing diurnal cycles, which naturally accommodates the seasonal and location-dependent variation in daytime length.

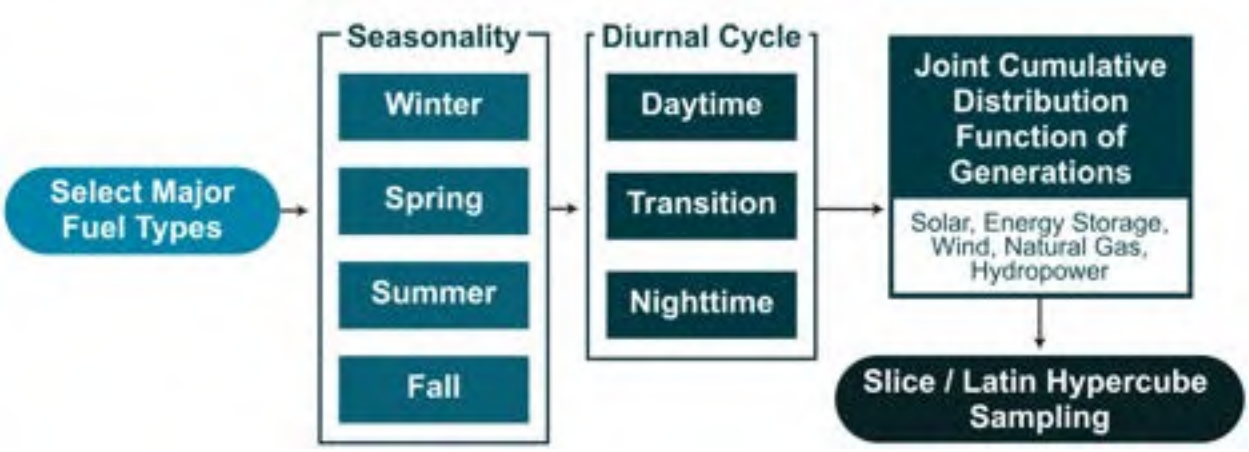



Figure 4. Sampling design that explicitly accounts for the seasonal and diurnal variations of renewable energy sources

As an example, for the AC scenario, the study team developed a dataset that contains the simulation results for 1 full year, e.g., 8,760 hours of the production cost model run. Statistical analysis of this dataset shows solar, energy storage (mainly utility-scale batteries), wind, natural gas, and hydropower account for more than 90% of the variance and overall contribution to the total generation. As such, the study team considered these five fuel types and the system load when sampling and validating representative hours.

The last step in the intelligent sampling method is to divide these data into 12 seasonal–diurnal bins. The Latin hypercube sampling with dependence (LHSD) method performed this division within each bin based on their respective joint CDF.

The study team identified representative hours for a variety of scenarios in this work but did not perform analyses for every representative hour. However, the study team conducted a contingency analysis on a subset of operating conditions chosen from the representative hours, and the results are detailed in the results section next. As a follow-up to this chapter, the study team recommends performing a detailed analysis of all representative hours.

## 2.4 Descriptions of the Transmission Expansion Scenarios

This section briefly describes the scenarios and datasets used to create the power flow scenarios. It provides context to the transmission and generation included in the power flow scenarios discussed in the rest of this report.

The NTP Study used the WECC 2030 Anchor Dataset (ADS) production cost model dataset as the starting nodal PCM case for the Western Interconnection. The ADS (WECC 2020a, 2020b) is the most reliable forecast for upcoming developments in new generation, generation retirements, transmission assets, and load growth, providing 10-year predictions from specified reference years.

The study team added transmission projects to the 2030 ADS that are either under construction or have significantly progressed through the permitting process and thus are deemed both plausible and likely to materialize. The capacity expansion modeling process of the NTP Study identified additional transmission capacity for the year 2035 (Chapter 2). The study team then converted the zonal models from the capacity expansion results to spatially detailed nodal production cost models for year 2035: the 1) Limited and 2) AC scenarios (Chapter 3).

These two scenarios have the same demand estimate from the capacity expansion model, which assumes 2.4% load growth per year until 2035 (as described in Chapter 1) and achieves 90% decarbonization by the year 2035, albeit through divergent transmission and generation capacity expansion strategies. The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., FERC Order No. 1000) whereas the 2035 Limited scenario permits transmission buildouts solely within these planning regions, with few exceptions for projects.

Figure 5 and Figure 6 show an overview of transmission expansion.

Figure 5. Transmission expansion in the 2035 Lim scenario from the 2030 ADS: 500-, 230-, and 345-kilovolt (kV) circuits are added or updated; new high-voltage direct current (HVDC) circuits are added

*BESS = battery energy storage system; PV = photovoltaic*

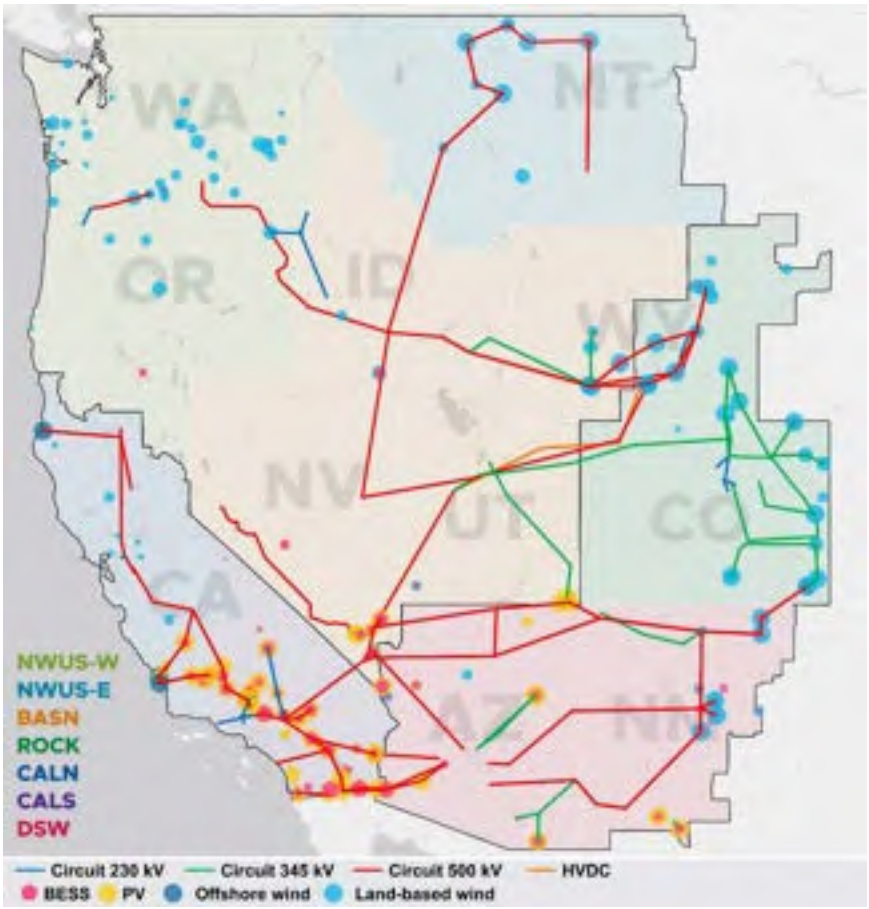



Figure 6. Transmission expansion in the 2035 AC scenario from the 2030 ADS: 500-, 230-, and 345-kV circuits are added or updated; new HVDC circuits are added

The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., FERC Order No. 1000) whereas the 2035 AC Limited scenario permits transmission buildouts solely within these planning regions. For the Western Interconnection, the FERC Order No. 1000 regions consist of the California Independent System Operator (CAISO), WestConnect, and NorthernGrid—whose borders are displayed in Figure 7.

Figure 7. Seven WECC subregions (excluding Alberta, British Columbia, and Northern Baja California Mexico): Basin (BASN), California North (CALN), California South (CALS), Desert Southwest (DSW), Northwest United States (NWUS), and Rocky Mountain (ROCK)

Figure 8 shows the additional generation capacity mix for the two transmission expansion scenarios (i.e., 2035 AC and Lim). Solar, wind, and storage are the largest capacity resources. The solar and storage capacity is mostly located in the California South and Desert Southwest regions for both derivative AC scenarios whereas the wind capacity is mostly located in the Northwest and Rocky Mountain regions.

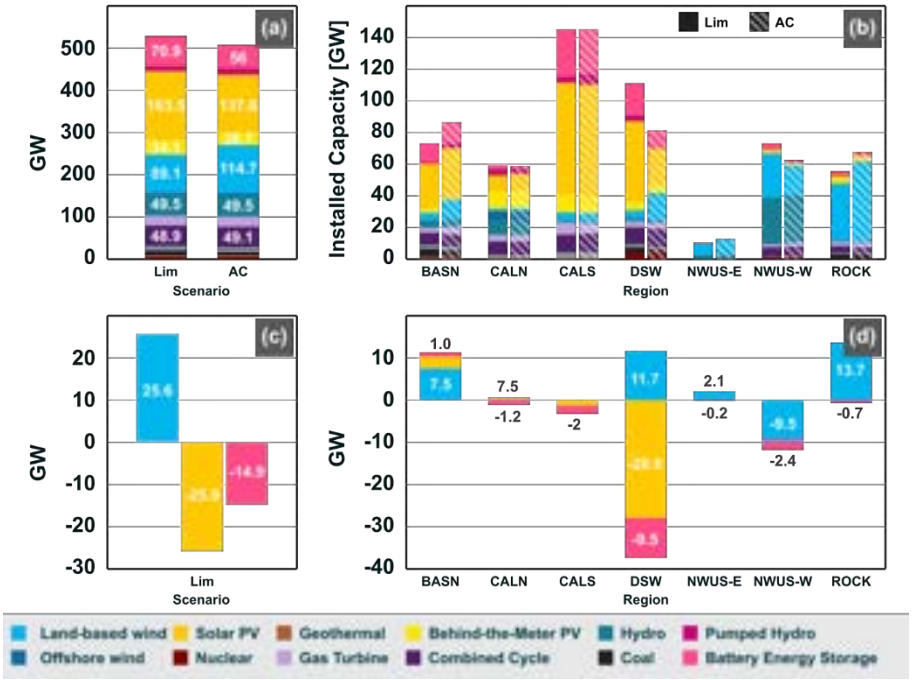



Figure 8. (a) Gen mix Lim vs. AC at interconnection level; (b) Gen mix Lim vs. AC at region level; (c) Gen mix difference Lim vs. AC at interconnection level; (d) Gen mix difference Lim vs. AC at region level

*GW = gigawatts*

## 2.5 Contingency Analysis

The purpose of the contingency analysis is to test the nodal transmission expansion scenarios' overall robustness and demonstrate the power flow case development method, which can also enhance more detailed reliability analysis. This contingency analysis is limited to the most critical and impactful contingencies recognized by the transmission planning community and does not begin to approach a full reliability planning study. For NTP Study purposes, the criteria for the selected contingencies are as follows:

- Make sure the new lines, mainly 500-kV lines, do not introduce new critical contingencies that negatively impact the reliability of the grid system. The study team selected individual outages of the newly added transmission and neighboring lines.
- Select large power plants 500 megawatts (MW) or above to understand the availability of the pseudo-governor response.

Table 1 lists the contingency limit monitoring settings only for buses and lines with a nominal voltage greater than or equal to 230 kV.

Table 1. Contingency Limit Monitoring Settings

| | Voltage Levels (kV) | Low (P.U.) | High (P.U.) |
|---|---|---|---|
| **Voltage limits** | 230 | 0.9 | 1.1 |
| | 345 | 0.9 | 1.1 |
| | 500 | 0.9 | 1.1 |

| | Normal | Contingency |
|---|---|---|
| **Line flow limits** | 100% of normal rating | Minimum of 130% of normal rating or 100% of emergency rating (if available) |

The analysis in this chapter evaluated three contingencies. Contingency #1 is the outage of two parallel lines that deliver power from a wind farm to load centers. These two lines carry 3,300 MW in the precontingency condition. The AC scenario uses this contingency. Contingency #2 is the outage of two of three parallel lines that connect 2,500 MW energy storage to the grid. These two lines deliver 2,000 MW in the precontingency condition. The Limited scenario uses this contingency. Contingency #3 is the outage of 2,600 MW of generation from a power plant. Both scenarios use this contingency.

# 3 Key Findings for AC Power Flow Analysis

This section provides the key findings based on the results of the power flow activities described in the methodology above.

## 3.1 Using Tools Refined in the NTP Study, Power Flow Cases With Different Generation Mix Can Be Extracted From Production Cost Model Simulations

### 3.1.1 The linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios

The study team successfully created the two power flow scenarios described in this report using the 2035 AC and 2035 Limited production cost models. The study team selected power flow snapshot cases for the 2035 AC scenario based on the intelligent sampling results next. The analysis in this chapter employed 24 of all the cases sampled. For these cases, the study team developed AC power flow models, including peak load models for different seasons, models that correlate to high solar penetrations, and models that show peak wind flow during the day. The linkage between the production cost model and the power flow model is critical for investigating the reliability of nodal scenarios with high penetrations of wind, solar, and battery storage—that is, the future decarbonized grid. Normally, this entire process may take a few weeks to months to create a base AC converged power flow case because it involves production cost modeling, AC convergence, and reactive power planning. C-PAGE enables power planners to generate many power flow cases in a matter of minutes per production cost model. The savings in staff time, ability to run time series data, and number of samples selected justify tools such as C-PAGE for becoming a standard in industry transmission planning. Linking power flow samples from one hour to the next is necessary to adequately evaluate the effects of shared ramping and variability hours across all scenarios. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.

### 3.1.2 Intelligent sampling is necessary when developing power flow models to account for the increasing variability of generation and load

Each day of the year and each hour of the day exhibit even distributions of significantly varying load, wind, solar, and online generation mixes within the same scenario. Figure 9 shows the final LHSD down-selected representative hours for the NTP Study 2035 AC scenario. Each day of the year and each hour of the day have even distributions for the 214 hours chosen by LHSD (sample size: 2.5%). This is the direct and desired outcome of regular interval slicing of the experimentally established CDF for all major fuel types. The definition of diurnal bins naturally divides a day into three groups while accounting for seasonal variations in daylight hours. This feature is observable in the seasonal variation of the vertical extension of the daytime and transition bins. This approach minimizes the computational cost and time expenses during AC power flow case conversion and accurately maintains statistical properties while accommodating the inherent natural variability among VRE sources and demand.

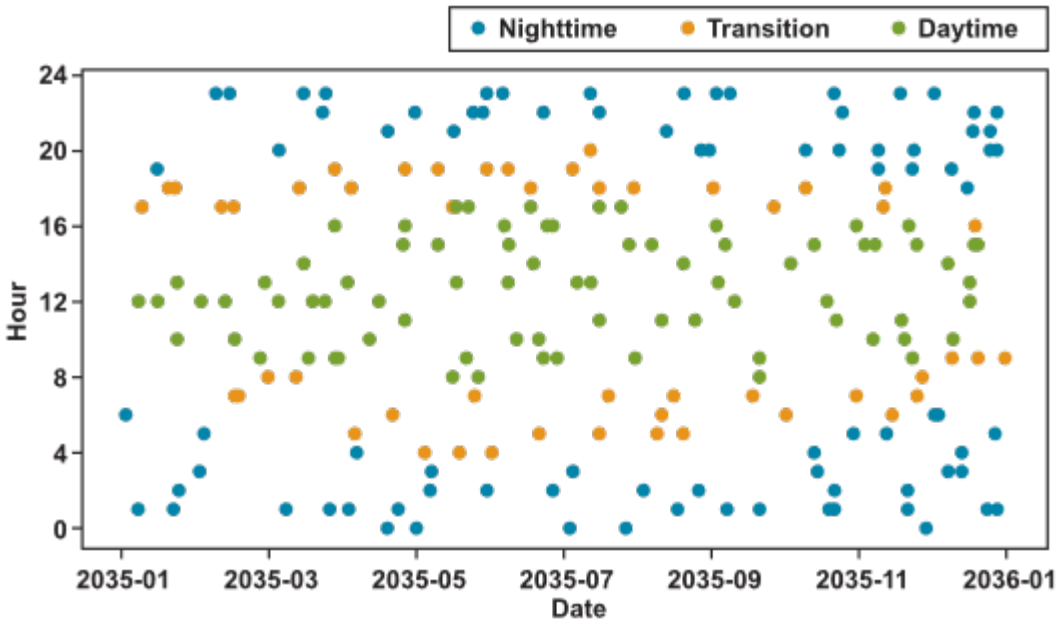



Figure 9. Distribution of the representative hours for the NTP 2035 AC case; the color scheme corresponds to different times of the day: blue signifies nighttime, yellow indicates transition periods, and green represents daytime

## 3.2 Power Grids With Large Transmission Buildouts and Clean Energy Penetration Can Be Planned To Withstand Contingencies

### 3.2.1 Outage of highly loaded new transmission buildouts do not introduce reliability risk in the developed scenarios

The contingency analyses presented in this chapter are only a preliminary indication of the robustness of the 2035 Limited and AC scenarios. The new transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded (closer to their normal ratings). Additional reliability studies are still needed to comprehensively assess the reliability in systems with large buildouts of high-voltage transmission lines, VRE and BESS, and changing load profiles. Providing the same level of voltage support as conventional power plants to prevent voltage instability and ensure proper power transfer to meet system reliability requirements will require new wind and solar projects.

#### *Contingencies for new lines in the Western Interconnection Limited scenario*

The study team evaluated the steady-state reliability of new transmission lines for the Limited scenario by simulating the contingency of two of three parallel, highly loaded transmission lines. The chosen line was to be highly loaded before the outage because this would have a huge influence on the line flows of the surrounding transmission lines. The study team analyzed the power flow at 4 p.m. mountain standard time (MST) on August 2, 2035, because high solar penetration caused the selected line to have the most loading on that day. After factoring in compensation from behind-the-meter (BTM) resources, the total load in the Western Interconnection amounted to 172 GW. Figure 10 shows the generation mix. Generation type “Other” represents the sum of several

small generators of different types such as geothermal, steam turbine-oil, bio-steam turbine, bio-internal combustion, combustion turbine-oil distillate, and bio-combined cycle. This corridor has three lines with a combined total normal rating of 6,500 MW and combined total real power flow of 2,700 MW before the contingency. Figure 11 displays the daily single-circuit flow of the selected line. The contingency trips two of the three circuits, resulting in an adjusted real power flow of about 1,900 MW through the single remaining line. This post-contingency loading of the remaining line is 88% of its normal rated capacity and 65% based on its emergency rating.

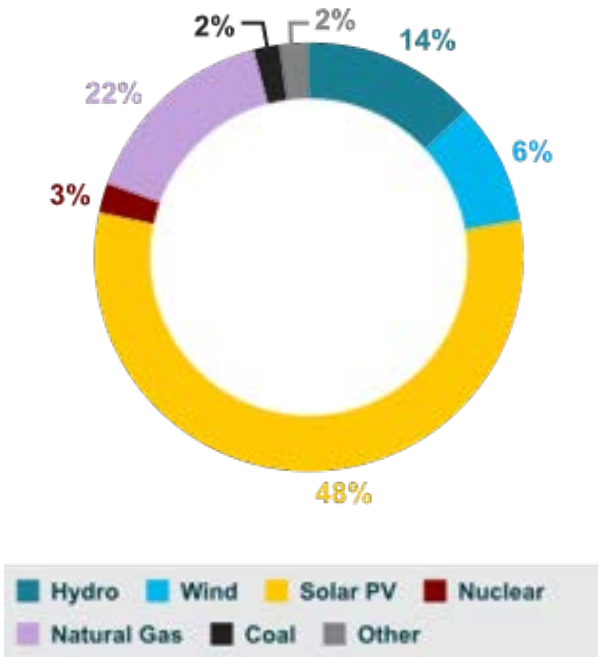



Figure 10. Generation mix at 4 p.m. MST on August 2, 2035

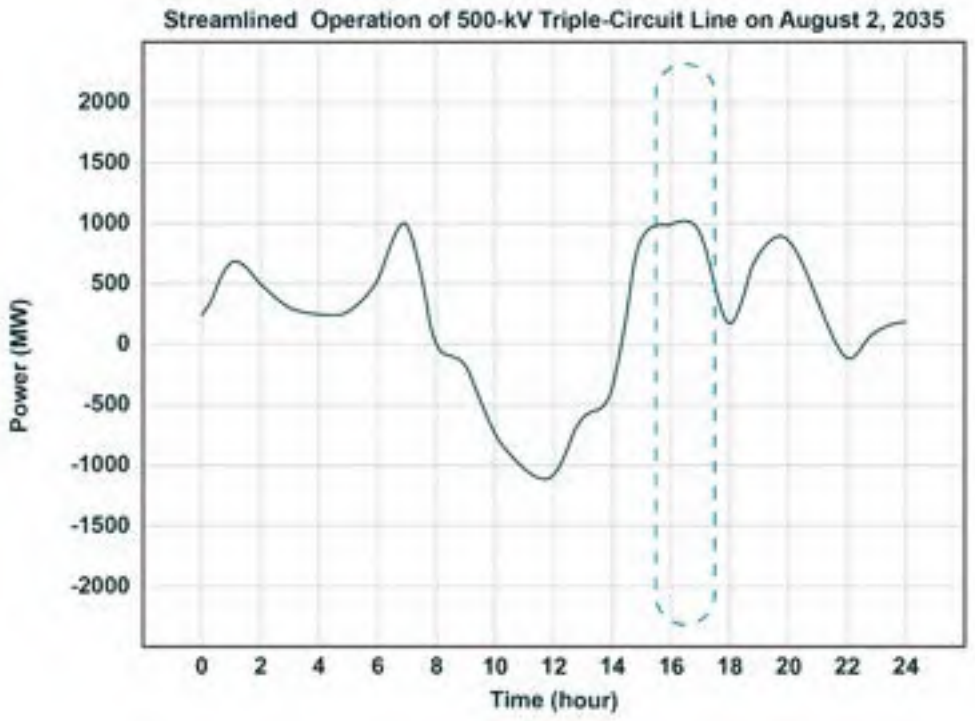



Figure 11. Single-circuit flow of the selected three parallel lines on August 2, 2035: Maximum loading time east to west

Figure 12 shows the changes to the transmission line power flows following the outage of the double-circuit transmission line. Lines with red, yellow, and green arrowheads show the power flow within the line exceeds 90% of its rated capacity, represents 50% to 90% of its rated capacity, and is less than 50% of its rated capacity, respectively. Figure 12(a) and (b) show the line flows pre- and postoutage, respectively. Two of the three parallel lines enclosed by the red cylinder in (a) are not operational. The contingency increases the load on the circuit that remains. This causes the flow on a line in New Mexico to revert to the north before sending power to Arizona and the West, as shown in (b).

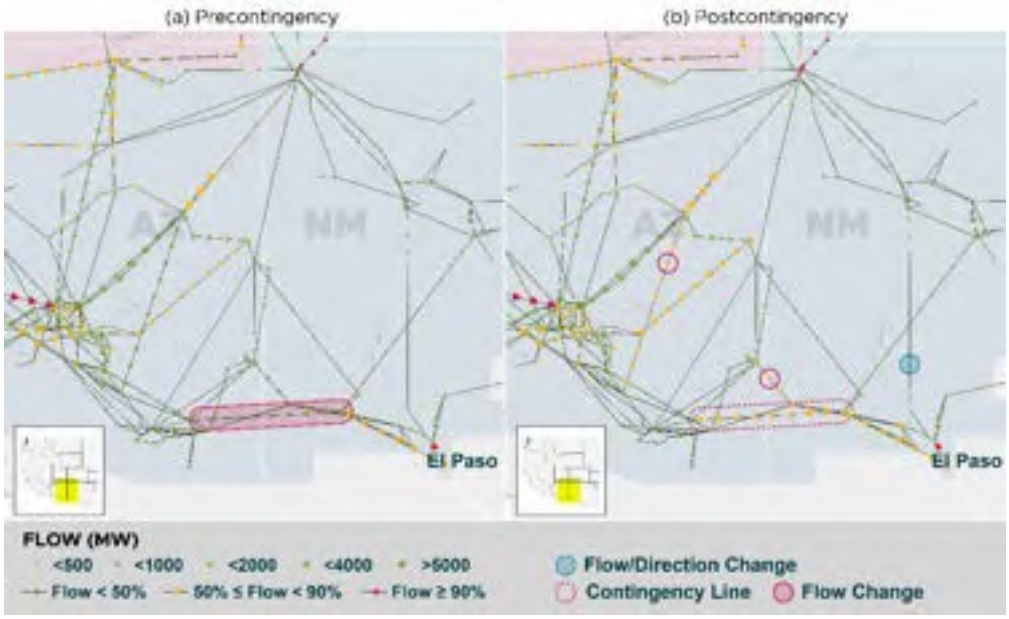



Figure 12. Lim contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes between southern New Mexico and Arizona; some flows reverse direction

A comparison of Figure 12(a) and (b) demonstrates 1) the channel from the El Paso Electric solar hub to the west is limited; thus, the flow is redirected north before moving west, and 2) the north-south flow reverses direction. Figure 13(a) and (b) depict the voltage magnitudes before and after the contingency, respectively. They also depict the flow of the Western Interconnection's high-voltage lines. Figure 12(b) shows some of the major variations in flow and flow direction close to the contingency line. Figure 13 shows there are not more voltage violations in the postcontingency situation beyond those observed in the precontingency condition.

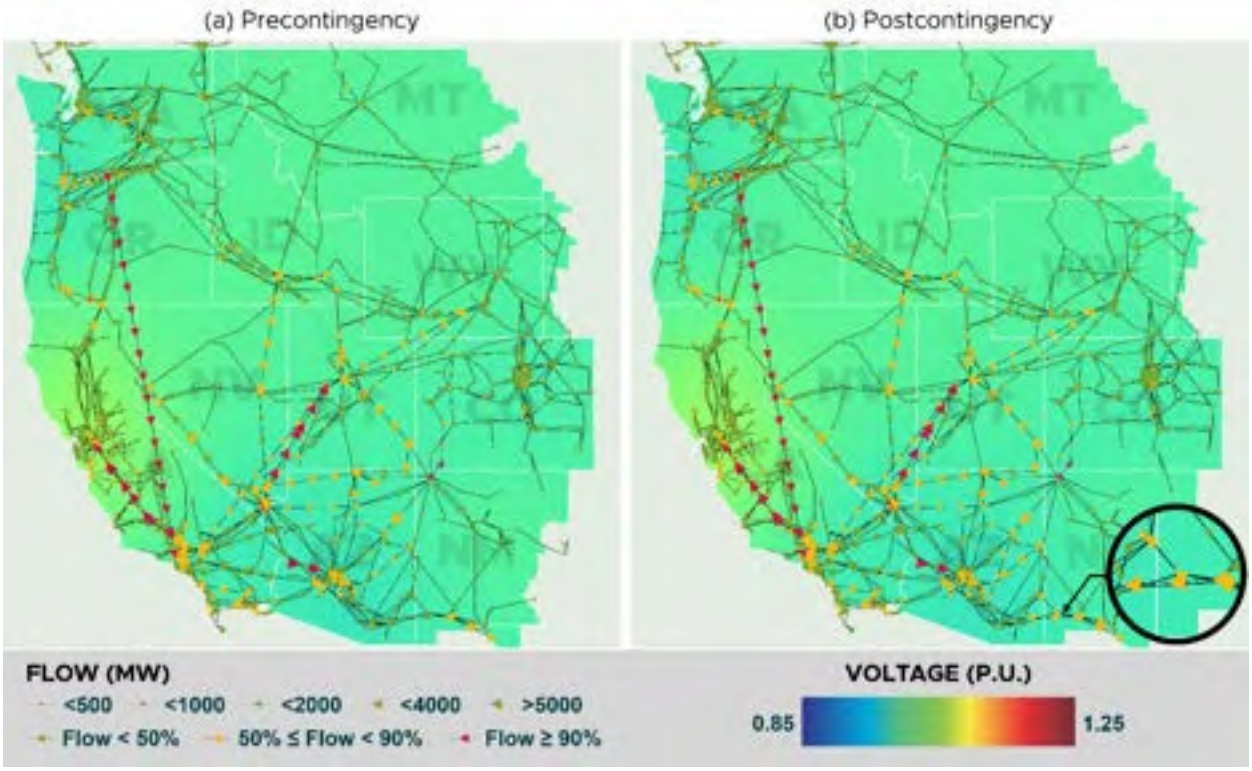



Figure 13. Lim AC contingency scenario: (a) pre- and (b) postcontingency system voltages; no significant voltage change following the contingency

### *Contingencies for new lines in the Western Interconnection AC scenario*

The study team evaluated the steady-state reliability of the new transmission lines within the AC scenario by performing a contingency analysis at 10 p.m. MST on August 2, 2035. The flow on the chosen contingency line—two 500-kV lines in parallel based in New Mexico—is at its peak during the day's high wind penetration levels at that hour. The total load in the Western Interconnection for the selected hour is 163 GW. Figure 14 displays the generation mix for this hour. Figure 15 shows the flow in one line of the two parallel 500-kV lines. Before the contingency, 2,600 MW flows through the selected line (two circuits). Postcontingency, when both lines are unavailable, power is rerouted.

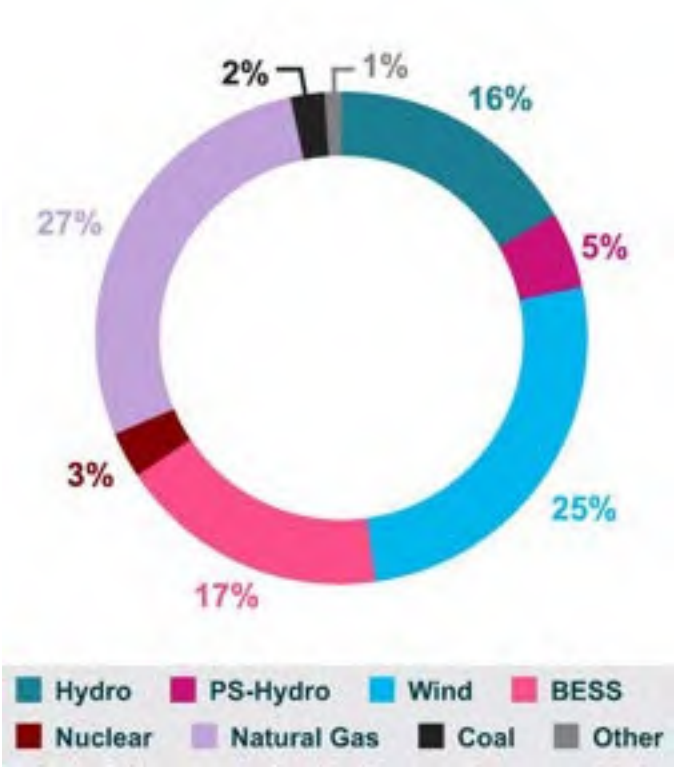



Figure 14. Generation mix at 10 p.m. MST on August 2, 2035: Natural gas and wind are the dominant generation

*PS = pumped storage*

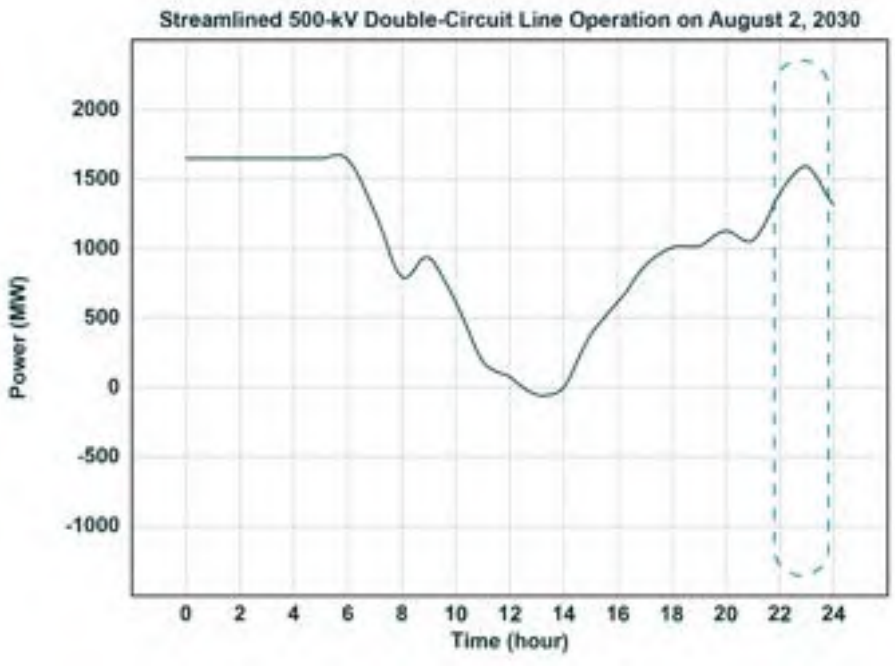



Figure 15. Single-circuit flow of the selected double-circuit 500-kV line on August 2, 2035: Nearly maximum loading time during high wind penetration

Figure 16(a) and (b) depict the pre- and postcontingency transmission power flows, respectively. The line surrounded by the red cylinder in (a) is the contingency. As a result of the contingency, more power is redirected to the north in New Mexico before being transferred to the west via Arizona and Utah. The contingency does not cause overloading on any other lines on the redirected paths, as shown in (b).

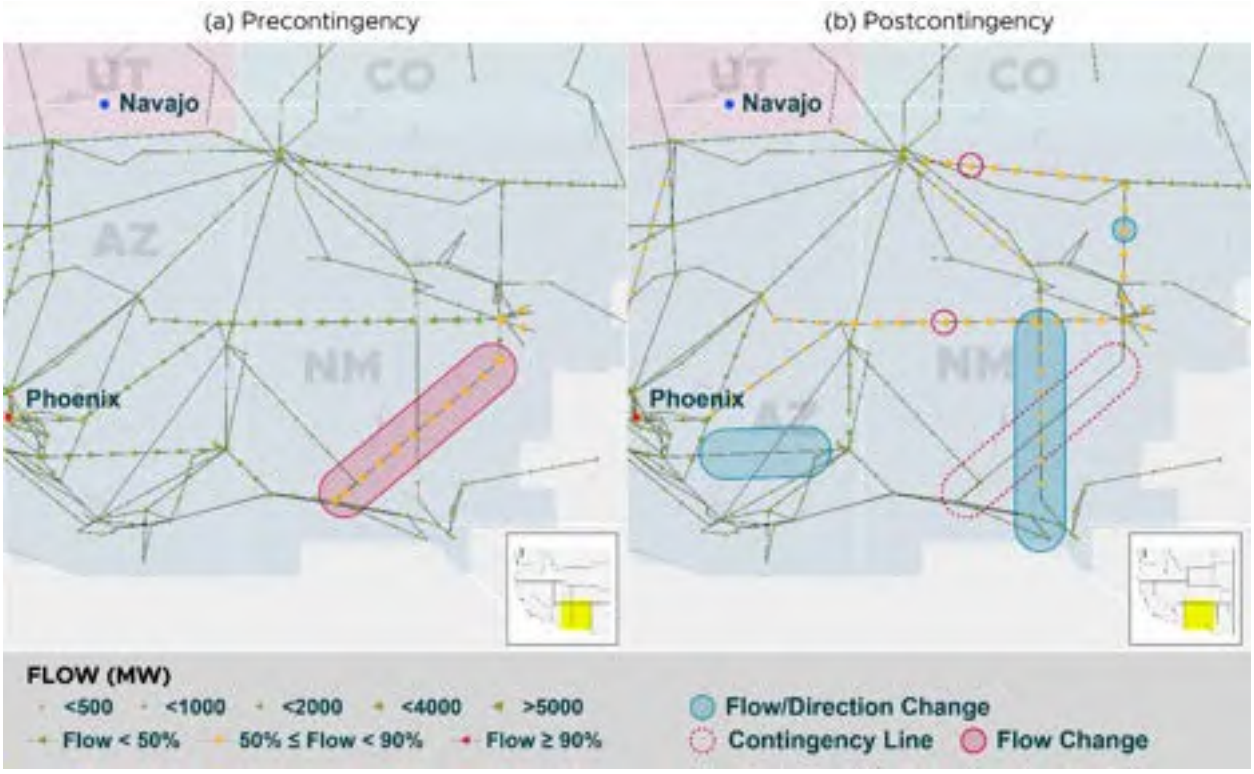



Figure 16. AC contingency scenario: (a) pre- and (b) postcontingency line flows; some flow changes in New Mexico as power was diverted north before it was sent to the West

A comparison of pre- and postcontingency power flows reveals 1) the flow into southeast New Mexico increases or reverses, 2) the flow from the central New Mexico wind hub increases through the western and northern paths (Coronado and Four Corners), and 3) the increased flow from Navajo replaces the flow received by Phoenix from southern New Mexico, as shown in (b). Figure 17(a) and (b) show heatmaps of the voltage magnitudes and line flows before and after the contingency, respectively. Figure 17 indicates no noticeable change in the voltage violation postcontingency beyond what is observed in precontingency. Figure 16 shows the alterations to the line flow after the contingency.

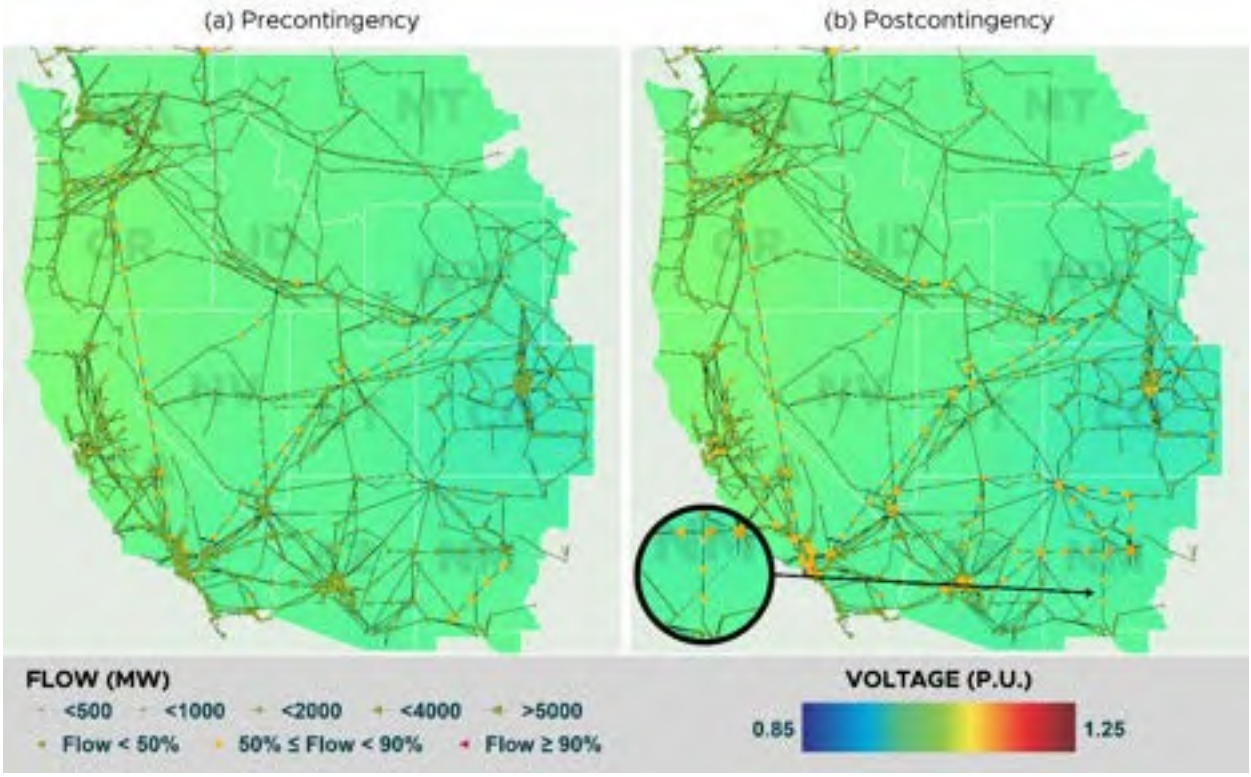


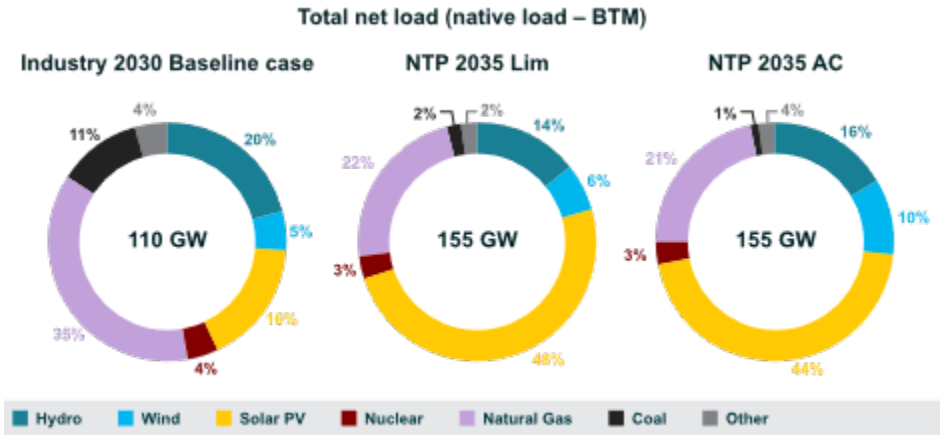

Figure 17. AC contingency study: System voltages before (left) and after (right) the contingency; there is not a significant voltage change following the contingency

### 3.2.2 Utility-scale battery storage plays a critical role in providing governor response during the outage of large power plants

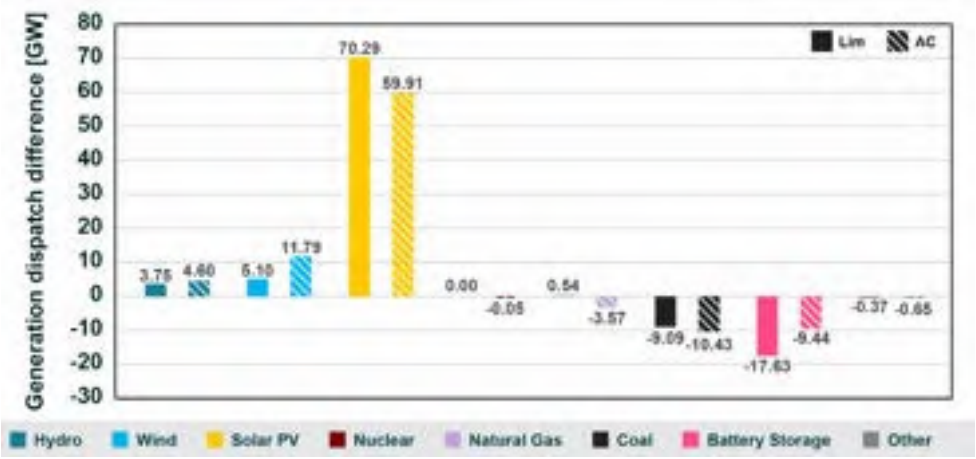
In highly interconnected transmission grids with high penetrations of VRE, this chapter shows large utility-scale BESS can play a key role in maintaining frequency response reserves. After the loss of a large generator, BESS can quickly either cease charging or increase generation (if there is sufficient headroom) faster than other types of generators to provide the necessary power to recover grid frequency.

As part of the contingency analysis, the analysis in this chapter evaluated the pseudo-governor response following the loss of a large generator in the two power flow scenarios. In this pseudo-governor response simulation, the generation redispatch compensates for an imbalance between generation and load at a predefined set of generators in the system in which the contribution of each generator is proportional to its capacity while respecting headroom limitations. For this analysis, the study team evaluated both power flow scenarios (Limited and AC) at the same hour—8 a.m. MST on July 21, 2035—and compared them to a power flow case exported from the 2030 ADS for 8 a.m. MST on July 21, 2030. The analysis in this study applied the same large generator outage to all power flow cases to assess the effects of the pseudo-governor response across each scenario. The contingency in this chapter is the loss of two nuclear generators at a single power plant with a total output of approximately 2,600 MW. Figure 18(a) shows the generation mix of the three scenarios, precontingency. Note all BESSs are charging, and the analysis considers them as loads

at this chosen hour in the three scenarios. Therefore, they do not contribute to the generation mix in the charts in this figure. Figure 18(b) shows the difference in generation dispatch in the NTP 2035 Limited and NTP 2035 AC scenarios from the industry 2030 Baseline by type. Solar dispatch is dominant in the Limited and AC scenarios because the solar capacity is much greater in the two scenarios compared with that in the Baseline scenario. The battery storage capacity in the Limited and AC scenarios is also much higher than that in the Baseline case. Note the negative value for battery storage in Figure 18(b) indicates they are charging (operated as load) during the hour of consideration.




(a)




(b)

Figure 18. (a) Precontingency generation mix for the 2030 ADS case as a reference industry case, 2035 Lim scenario, and 2035 AC scenario: The NTP Study evaluated scenarios that have more renewable generation than the Baseline case, especially high solar penetration; (b) generation dispatch difference by type in the 2035 Lim and AC scenarios from the 2030 ADS case

Figure 19 shows the generation redispatch by type to make up for the loss of 2,600 MW of generation. Notice solar and wind do not participate in the redispatch because they have no headroom—nor coal because its governors are typically slow to react or are disabled. At the time of the generator loss, BESS devices in the system are charging,

and BESS has enough reserved energy to cease charging and ramp up its generation to participate in the pseudo-governor response process. BESS devices are also dispatchable at any stage of their operation. A positive BESS redispatch after the contingency means it charges at a lower level to decrease its consumption.

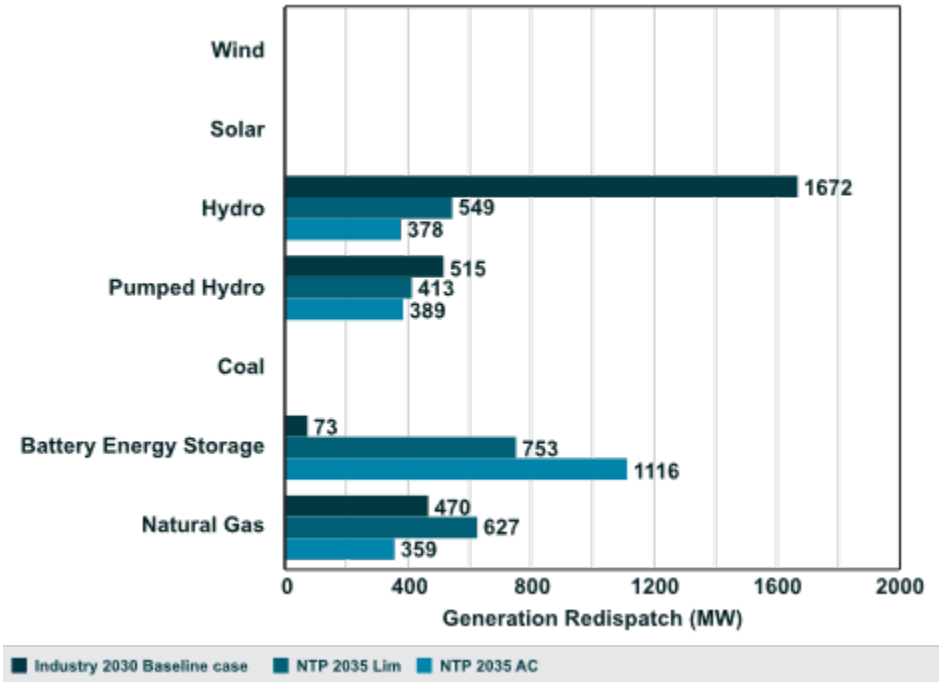



Figure 19. Generation redispatch after the loss of 2,600 MW of generation: BESS, Hydro, Natural Gas, PS-Hydro dispatch; Hydro accounts for the greatest contribution in the ADS case redispatch; BESS has the greatest contributions in both NTP AC and Lim scenarios

Figure 20, Figure 21, and Figure 22 show the pre- and postcontingency voltage heatmaps and transmission line power flows for all three scenarios.

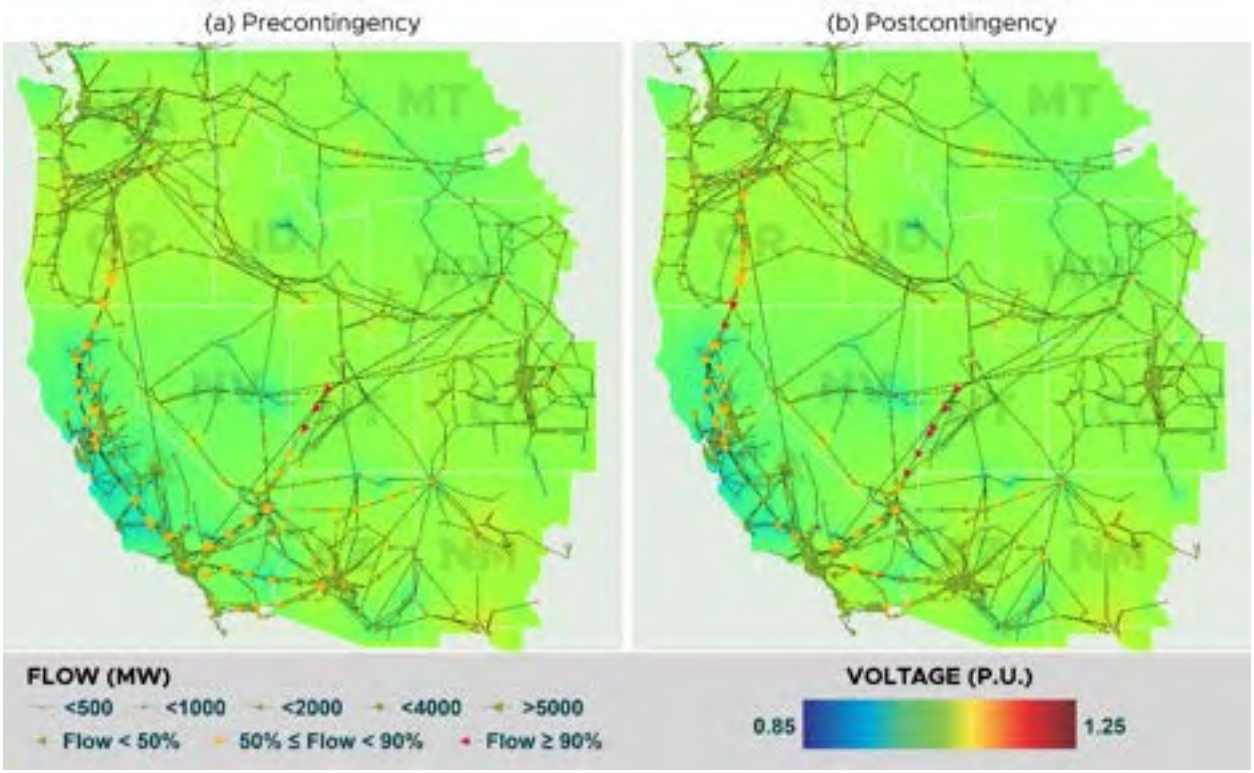



Figure 20. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the 2030 ADS case: No significant voltage changes following the contingency

For the Limited scenario, as seen from Figure 21, there are no significant changes in the voltage profile, and the line flows overload because of the loss of 2,600 MW. Therefore, the study team assessed the scenario as robust and relevant for further study and analysis.

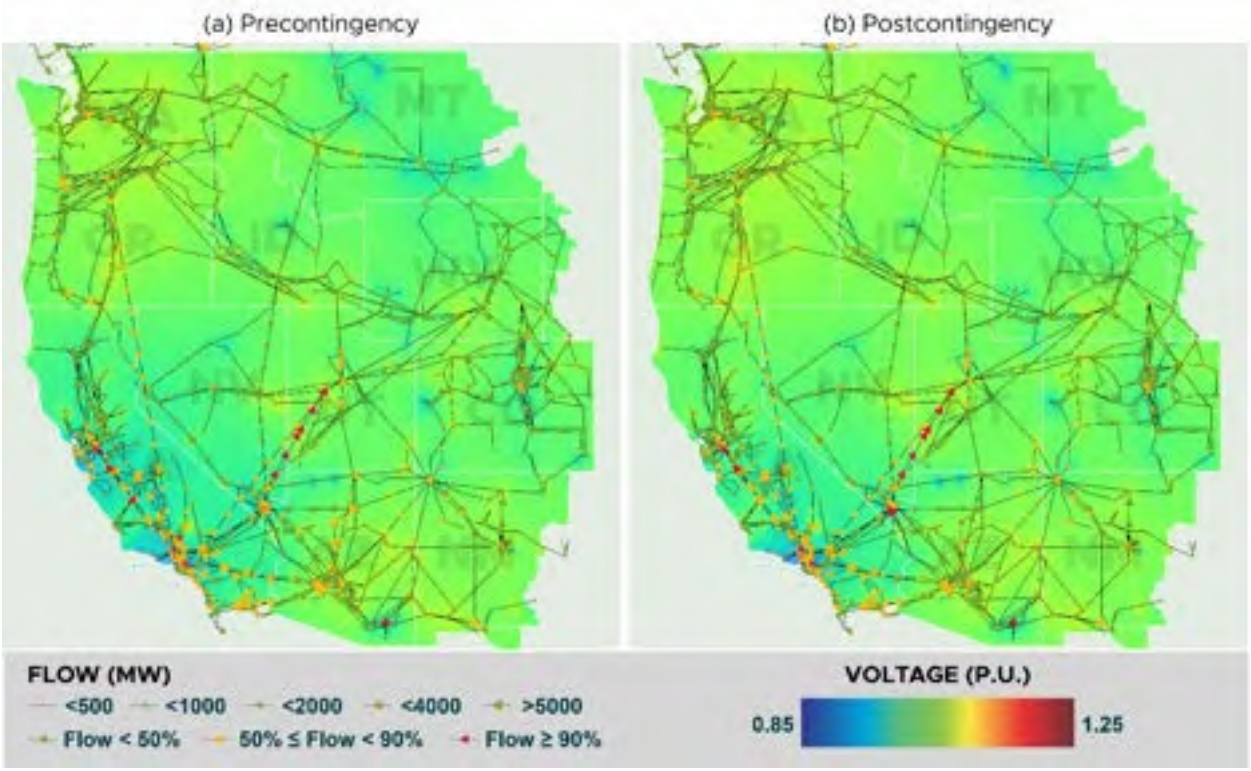



Figure 21. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the Lim scenario: No significant voltage changes following the contingency

For the AC scenario, as seen from Figure 22, there are no significant changes in the voltage profile because of the loss of 2,600 MW. The loss of power delivered to California from Arizona is primarily compensated by Utah and Las Vegas, Nevada. The changes in power delivery pattern help reduce the overload on the path from Southern to Northern California.

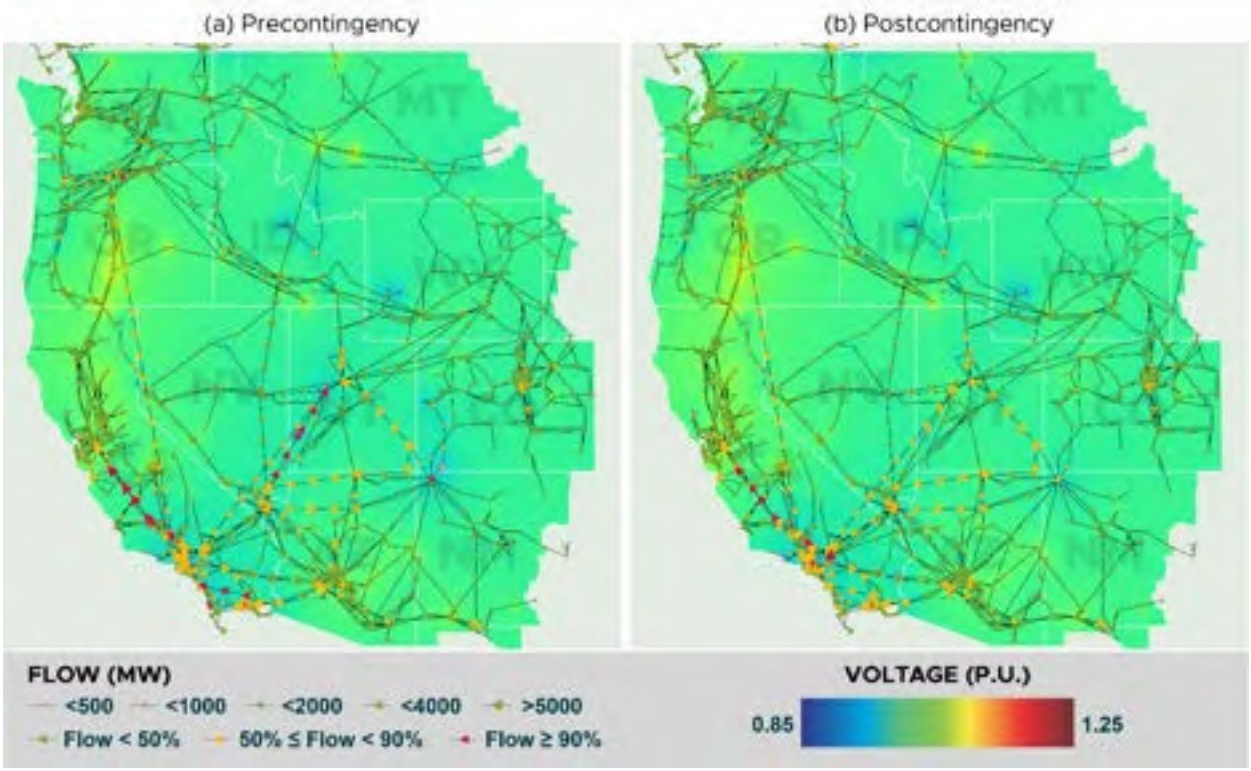



Figure 22. Voltage heatmaps (a) pre- and (b) postcontingency for the loss of 2,600 MW of generation at a nuclear power plant for the AC scenario: No significant voltage changes following the contingency

## 3.3 Advanced Data Analytics Developed in This Study Can Help Industry Understand Grid Behavior for Many AC Power Flow Hourly Snapshots and Contingencies

The study team needed and used the interactive visualization and a database management system throughout the NTP Study to visually explore and analyze system behavior. The study team developed advanced data analytics to handle a large set of results, analyzing several power flow cases with contingencies and comparing grid performance between several capacity expansion scenarios for future studies.

The study team developed Python automation scripts that enable the efficient handling of large-scale power flow datasets produced by production cost model, power flow, and contingency analysis tools. These scripts use QGIS to facilitate the automated generation of detailed, interactive maps that display power flow information, such as the transmission grid topography, voltage profiles, and transmission line loading. Full back-to-back automation allows users to extract power flow information from solvers (usually stored in binary files), process it, and upload it to the database server to generate GIS visualizations (QGIS layers) and unique QGIS projects for specific power flow cases or scenarios. The analytics module ranks all simulated contingencies across all events and situations, allowing the user to choose where to zoom in for more extensive analysis. This module supports future integration with industry-standard Big Data analytical and interactive visualization tools. Appendix C describes the specifics of these components, which are exemplified in some of the graphics within this report.

# 4 Conclusions

Through the development and contingency analyses of two transmission power flow scenarios—the Limited and AC high-demand scenarios both with 90% decarbonization by 2035—the analysis in this chapter verified the robustness of certain transmission expansion scenarios developed in the capacity expansion modeling and production cost model portions of the NTP Study. During the NTP Study, the study team developed an automated conversion tool that exports generator dispatch from a production cost model to an AC power flow model. The methods outlined in this chapter will enable planning engineers to perform detailed transmission planning studies on large interregional systems with high penetrations of VRE and BESS.

This chapter shows large, interregional systems can maintain voltages within acceptable ranges, given careful reactive power planning. The conversion tool the study team developed and used in this chapter is complemented by an intelligent statistical sampling method to select a representative range of dispatch conditions throughout a year for power flow analysis. Finally, in this chapter, the study team has designed an interactive visualization and database management system to assist transmission planning engineers in visually exploring and analyzing system behavior.

Key takeaways of this chapter include the following:

- **Using tools refined in the NTP Study, power flow cases with different generation mixes can be extracted from production cost model simulations.** Intelligent sampling methods, such as those applied in this chapter, should be used to select representative hours from the production cost model for the power flow analysis because planning engineers face significantly varying load, wind, solar, and online generation mixes within the same scenario. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.
- **Power grids with large transmission buildouts and clean energy penetration can be planned to withstand contingencies.** New transmission lines associated with the scenarios can be planned to avoid voltage or thermal loading risks to the system, even when they are highly loaded. Utility-scale storage can play a key role in providing the primary frequency response for large power plant contingencies. However, a full reliability analysis is necessary for new grid infrastructure.
- **Advanced data analytics developed in this study can help industry understand grid behavior for many AC power flow hourly snapshots and contingencies.** The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies.

Future areas of recommended study include additional contingency analyses for combined Eastern and Western Interconnection scenarios under many single and multiple contingencies and several different operating conditions. In addition, future research should include contingency analyses using dynamic simulation to examine the developed grid models for characteristics such as the frequency response and voltage ride-through during grid disturbances.

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# Appendix A. Compatibility Issues Between the Production Cost Model and the Power Flow Model

## A.1 Linkage Between the Production Cost Model and the Power Flow Model (test and validation)

To ensure consistency between the production cost model (PCM) and power flow model, the study team conducted a componentwise (bus, generator, bus load, and transmission line/transformer, high-voltage direct current [HVDC] interface) comparison between the two models' databases. Note each component in one model must have the same or an equivalent component in the other model. If one component exists in one model but not in the other, the study team normalized the models by either adding the component or removing it from a model to maintain equivalency. Appendix B includes examples of how compatibility issues between the two models for specific network components were handled.

The analysis in this chapter used Python scripts to modify all models. To verify the validity of the model, the study team gradually performed test runs for the modified production cost model along with the model modifications.

### Model modifications

1. **Buses:** A comparison of the buses from the power flow model and the production cost model revealed the study team identified 27 buses in the production cost model that were absent from the power flow model and 8 buses in the power flow model that were also absent from the production cost model. The study team added those buses to the corresponding model to ensure they matched.

2. **Loads:** A comparison identified nine bus loads in the power flow model but not in the production cost model. The study team added them to the production cost model to match those in the power flow model.

3. **Transmission lines/transformers:** An initial comparison of the lines/transformers in the two models resulted in many mismatches. A detailed investigation of the mismatches identified each mismatch is because of one or more of the following reasons:

    - The three-winding transformers in the power flow and production cost models are modeled differently.
    - The lines/transformers have the same from bus and to bus but different circuit IDs.
    - Several lines/transformers exist in one model but not in the other.

    After addressing these mismatches, the study team identified 18 lines/transformers that still exist in the power flow model but not in the production

cost model and 42 lines that exist in the production cost model but not in the power flow model. The study team added those lines/transformers to the corresponding models.

4. **Generators:** A comparison of the generators in the production cost and power flow models identified many differences. Several hundred generators exist in one model but not in the other. There are several reasons for these differences:

   - One model added new variable renewable energy generators but not the other.
   - One model removed some retired generators but not the other.
   - The same generator is present but connected to the system at different voltage levels in the two models.
   - The same generator is present with different IDs in each model.
   - The same generator is present but connected to different buses in each model (i.e., the bus was renumbered).
   - One model modeled the power plant at the plant level (“lumped” unit) versus several generators at the bus level in the other model.
   - There were duplicated generators at the same bus (several generators with the same identification [ID] connected at the same bus).
   - The production cost model contained generators that were connected at buses that do not exist in the system.
   - The power flow model modeled generators as a synchronous condenser, and these generators do not exist in the production cost model.

   Figure A-1 and Figure A-2 show examples of generator mismatches between the two models.

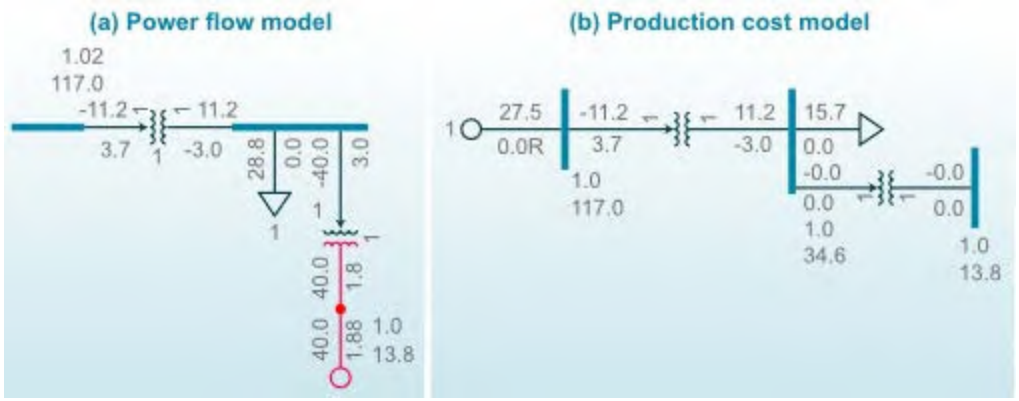


Figure A-1. Same generators modeled at different buses in the (a) power flow and (b) production cost models

Figure A-2. Generators modeled as one lumped unit versus several distributed units at the same bus in the (a) power flow and (b) production cost models

After considering all the factors mentioned previously, the comparison identified 112 generators that exist in the power flow model but not in the production cost model and 650 generators that exist in the production cost model but not in the power flow model. Because the generator datasets in the power flow model do not provide enough information (fuel price, heat rate, startup/shutdown cost for thermal units, hourly profile for renewable units, and so on) to implement in the production cost model, the study team removed generators that exist in the power flow model but not in the production cost model. For generators that exist in the production cost model but not in the power flow model, the study team added them to the power flow model. To reduce the complexity of the dynamics model later, the study team removed the units with a capacity less than 20 megawatts (MW) from the production cost model instead of adding them to the power flow model. With this simplification, the power flow model now includes only 320 generators.

5. **HVDC:** The high-voltage direct current is modeled to allow power flow in only one direction in the power flow model whereas in the production cost model, power is allowed to flow in either direction. Hence, when importing the scheduled power for an HVDC with the flow direction reversed, users must reverse the converters' functionality (rectifier vs. inverter) at both ends.

6. **Interface definition checks and modifications:** The two models have different definitions of several interfaces. The reasons for the differences are as follows:
    - The interfaces comprise different numbers of transmission lines in both models.
    - The interfaces comprise the same number of transmission lines but are defined in opposite directions in the two models.

The study team identified and corrected all differences along with their corresponding flow limits in one or both models to match them.

After the study team addressed all inconsistencies between the component datasets of the two models, components in the two models were added or removed via the following steps:

1. Add new generators: After the new buses are added, add the required number of new generators.
2. Add new buses.
3. Add new lines/transformers.
4. Remove generators in the power flow model but not in the production cost model.

The study team developed several EPCL scripts to add components to the power flow model. To maintain the converged power flow case, the study team solved the power flow model after each modification.

Steps to add/remove components to/from the production cost model database:

1. Add new buses.
2. Add new lines.
3. Add new loads.
4. Remove generators that do not exist in the power flow model and with a capacity less than 20 MW.

## Model validation

The study team imported the dispatch results from the production cost model into the power flow and obtained a solution for the DC power flow. A comparison of the line/interface flows validated the mapping between the two models. Temporal snapshots showed the closeness of the power flow pattern between power flow cases and the production cost model. In addition, the study team performed a statistical analysis to measure the goodness-of-fit of the modeling transformation.

*Production cost model vs. DC flow comparison for the 2035 Alternating Current (AC) scenario*

For the 2035 AC scenario, the study team created 24-hour cases on the peak load day (July 29) and compared them with the production cost model, as shown in Figure A-3 to Figure A-6.

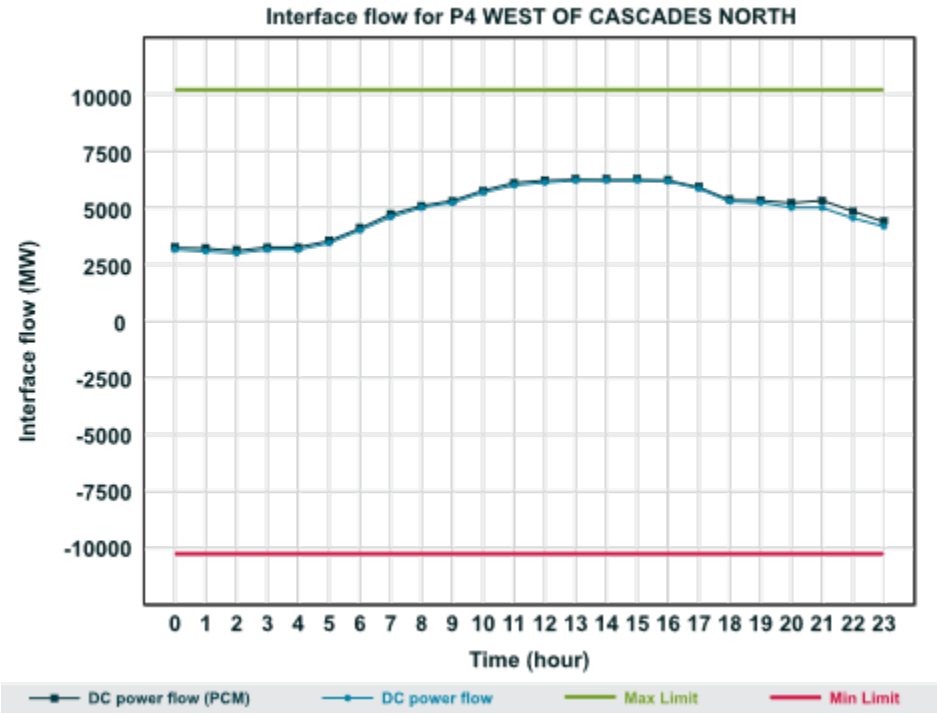


Figure A-3. Interface flow for Path P4 on July 19 (2035 AC scenario)

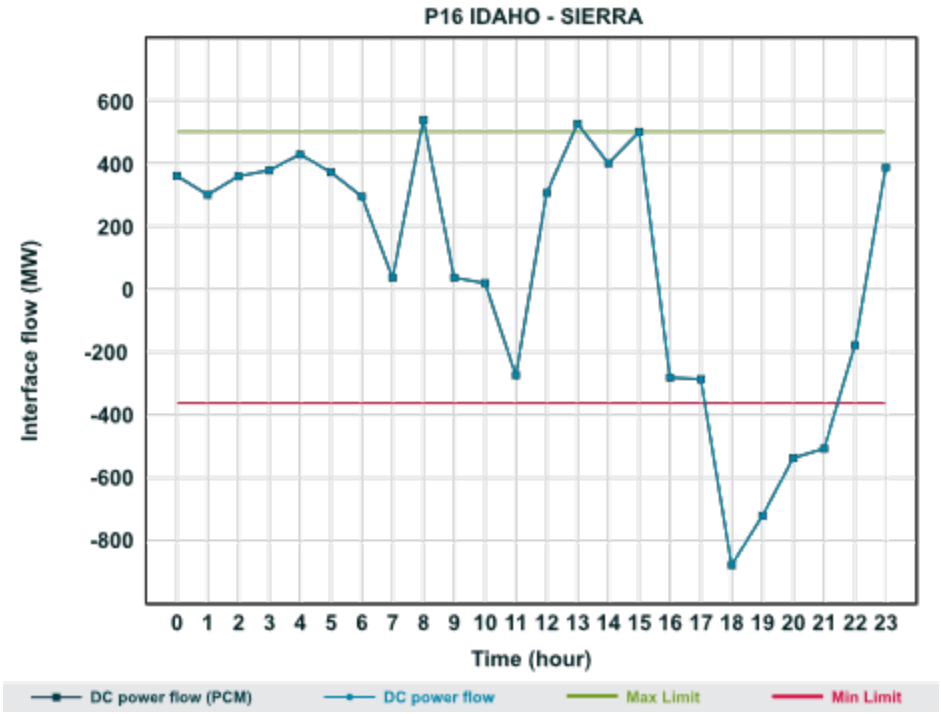


Figure A-4. Interface flow for Path P4 on July 19 (2035 AC scenario)

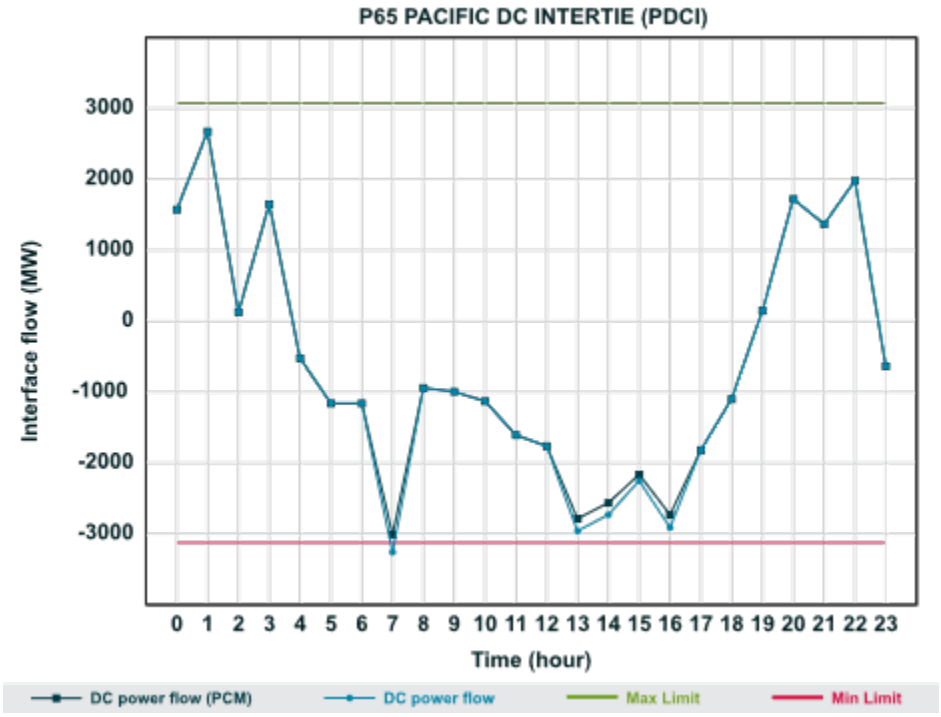


Figure A-5. Interface flow for Path P65 on July 19 (2035 AC scenario)

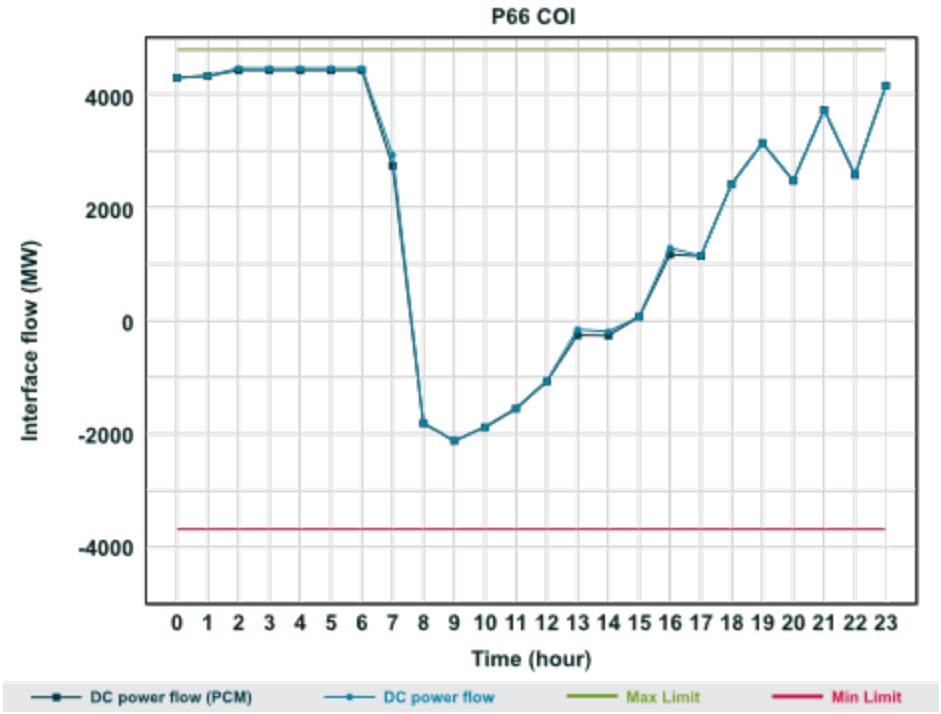


Figure A-6. Interface flow for Path P66 on July 19 (2035 AC scenario)

*Production cost model vs. DC flow comparison for the 2035 Limited (Lim) scenario*

For the 2035 Limited scenario, the study team created 24-hour cases on the peak load day (July 29) and compared them with the production cost model, as shown in Figure A-7 through Figure A-10.

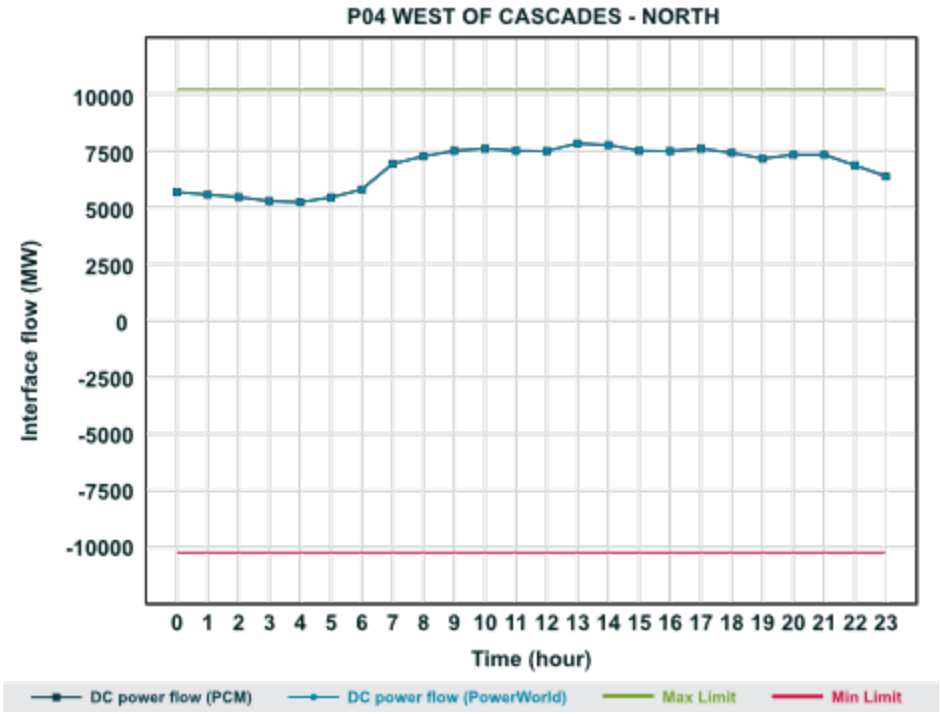


Figure A-7. Interface flow for Path P4 on July 29 (2035 Lim case)

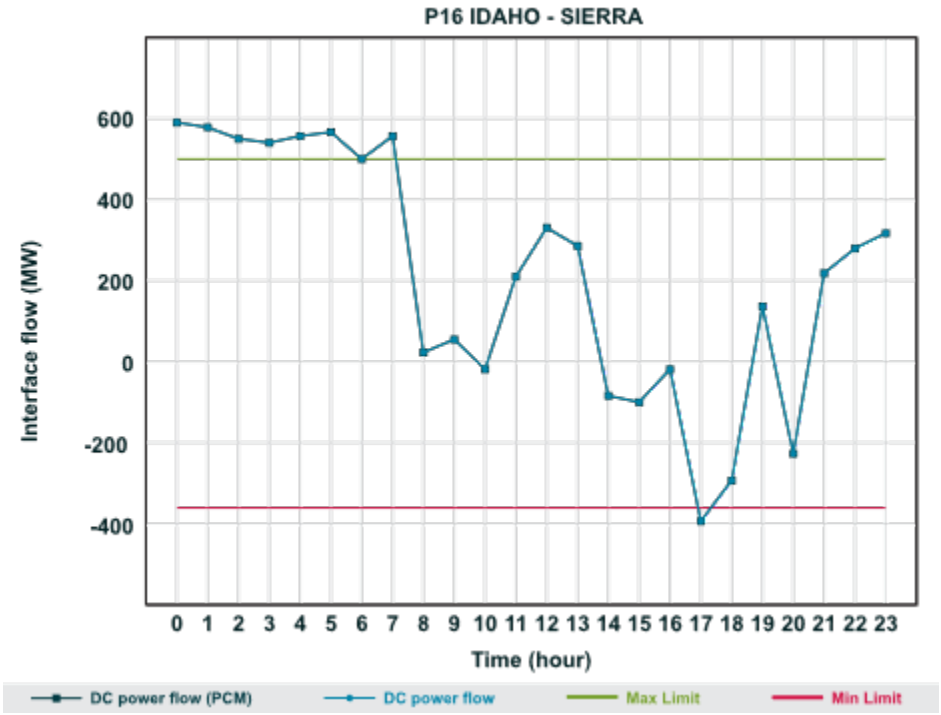


Figure A-8. Interface flow for Path P16 on July 29 (2035 Lim case)

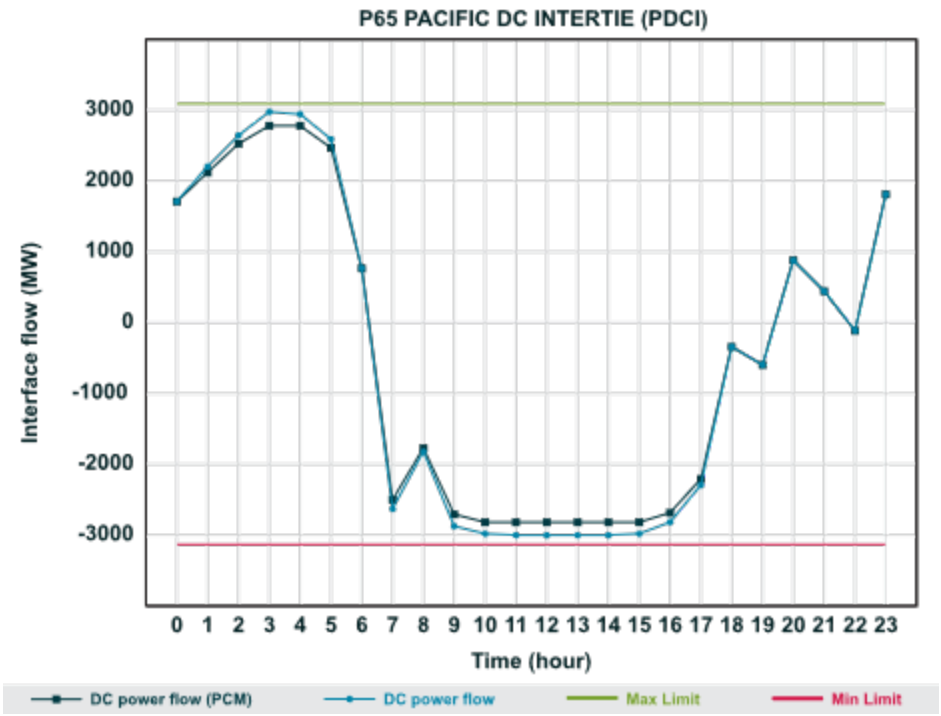


Figure A-9. Interface flow for Path P65 on July 29 (2035 Lim case)

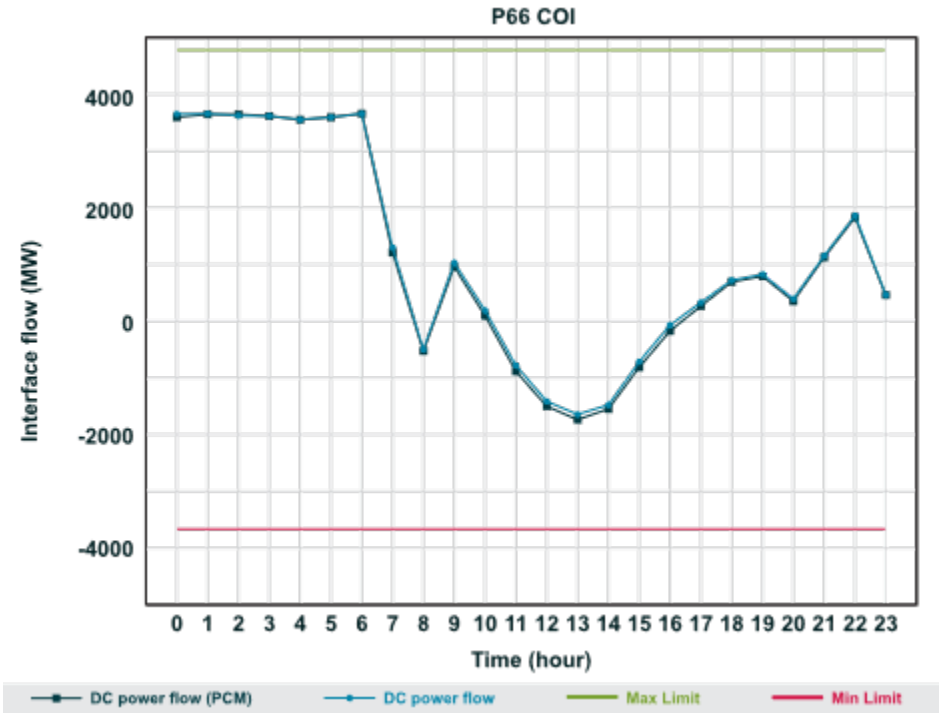


Figure A-10. Interface flow for Path P66 on July 29 (2035 Lim case)

In general, the results show acceptable consistency in the interface and branch flows for the production cost model and the exported power flow case.

The study team performed a statistical analysis of the exported power flow cases for the entire year to capture the accuracy and deviation from the PCM. This analysis computed the differences in the power flows on system transmission lines and at interfaces. The study team normalized the magnitudes of these differences by the component rating to quantify the deviation in the error between the power flow and production cost models. In the boxplots that follow, the positive error means the flow in the power flow model is higher than that in the production cost model.

Figure A-11(a) shows the error between flows from the power flow and production cost models on transmission lines categorized by voltage level whereas Figure A-11(b) shows the percentage error of the normalized transmission line flows. The average errors on the 230-, 345-, and 500-kilovolt (kV) lines are −6.3, 11.2, and 34 MW, respectively. Though the 230-kV transmission lines have a smaller error compared to the 500-kV transmission lines, the percentage error is slightly wider because the number of monitored 230-kV transmission lines is much larger than that of 500-kV lines. Moreover, the average percentage errors are −0.4%, 2.4%, and 2.8% for the 230-, 345-, and 500-kV lines, respectively. These are very small errors for the transformation of the PCM into power flow cases.

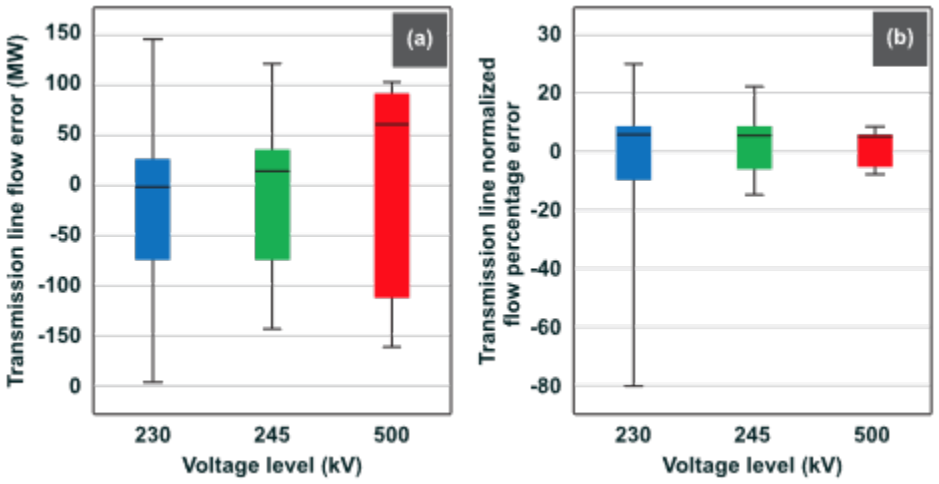


Figure A-11. Boxplots of the transmission line (a) flow error and (b) percentage error between the power flow and production cost models

Figure A-12(a) and (b) show the error and percentage error between flows from the power flow and production cost models on the interfaces defined in the system, respectively. The average error and average percentage error on the interfaces are −26.8 MW and −12.4%, respectively.

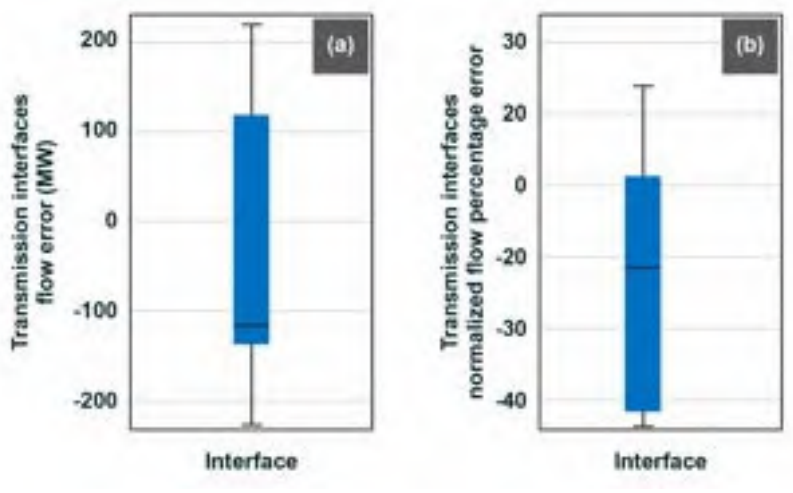


Figure A-12. Boxplots of the transmission interface (a) flow error and (b) percentage error between the power flow and production cost models

## A.2 Production Cost Model Postprocessing Redispatch Procedure

The results generated by the PCM require additional analysis and data processing to prepare for the power flow and contingency analyses. The PCM postprocessing procedure comprises three main phases: a) redispatch hydropower plants, b) redispatch variable renewable energy (VRE), and c) make system-specific modifications. The following describes these phases:

1. **Redispatch hydropower plants:** GridView (Hitachi ABB 2024) models the hydropower generation at a given hydropower plant as several units. It conducts hydropower generation dispatch globally at the plant scale. Then, it computes the amount of generation from each unit within a hydropower plant based on the unit rating. In other words, GridView splits the total hydropower plant generation among all hydropower units in proportion to their rating; e.g., a total hydropower dispatch of 10 MW is split equally across 10 hydropower units—assuming all units have the same rating. If the capacity rating of each hydropower unit is 2 MW, each unit is 50% loaded. In this way, all hydropower units have the same participation (loading) factor. However, in real systems, not all hydropower units run simultaneously. Determining the number of active (running) hydropower units requires knowing 1) the ratio of the amount of generation dispatch to the total power capacity and 2) a given priority list. For the previously mentioned example, assuming the hydropower units have the same priority, the number of active units is five (50% of the number of plant units). This is calculated by dividing the amount of dispatch (10 MW) by the total power plant capacity (20 MW), resulting in five fully loaded units, with the remaining units unloaded.

   On the other hand, the capacity limit of each hydropower unit varies seasonally and is not fixed across the whole year. This variation impacts the number of dispatchable hydropower units at a particular time instant. If the summer limit for the previous example is reduced to 1.5 MW per unit, for the same scenario,

seven hydropower units are dispatchable [10/(1.5 × 10) = 0.67% → 70% of the number of units]. In this case, the resulting capacity mix includes six fully loaded units with a total generation of 9 MW, one unit generating 1 MW, and three unloaded units. The GridView model considers seasonal changes, and power flow cases should preserve these considerations. Table A-1 and Table A-2 summarize the differences in hydropower dispatch accounting for prioritization, loading distribution, and seasonal limits.

Table A-1. Redispatched Hydropower Units Considering the Loading Distribution and Modified Capacity Limits

| Unit Number | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Power generation profile from GridView | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Redispatched power considering loading distribution | 2 | 2 | 2 | 2 | 2 | 0 | 0 | 0 | 0 | 0 |
| Redispatched power considering reduced unit limits to 1.5 MW | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1 | 0 | 0 | 0 |

Table A-2. Redispatched Hydropower Units Considering Prioritization and Different Unit Capacity Limits

| Unit Number | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Capacity limit (MW) | 1 | 2 | 1 | 2 | 0.5 | 0.5 | 2.5 | 2.5 | 1 | 1 |
| Priority | 3 | 2 | 7 | 6 | 4 | 10 | 1 | 5 | 8 | 9 |
| Power generation profile from GridView | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Power generation profile from GridView | 1 | 2 | 0 | 1.5 | 0.5 | 0 | 2.5 | 2.5 | 0 | 0 |

To address these challenges, the study team prepared a two-step Python-based script to redispatch hydropower generation. First, the script extracts the results from GridView and computes the total generation of each hydropower plant by aggregating the power generated by each unit within the power plant. Then, it uses a priority list of each power plant to commit individual units. The script redispatches hydropower units sequentially until the total amount dispatched equals the precalculated aggregation generation plus the required reserve generation. In this step, the script adopts the capacity limit of each unit from the

GridView results and assumes the status of unloaded units is “off” and should not contribute to power flow cases.

2. **Redispatch VRE:** GridView conducts renewable energy generation globally on the plant level. This results in distributing the total plant dispatch value equally across all connected units. However, for a particular renewable power plant (solar, wind, and battery storage), the number of units in GridView is usually different from the number of installed units in power flow cases. Generally, the study team observed fewer units in GridView because the GridView model aggregates very-small-scale units at nearby geographical locations into a single point of interconnection. Accordingly, the amount of unit dispatch will change according to the ratio between the amount of plant dispatch and the corresponding number of units in power flow cases. Moreover, it is important to enforce the status of battery storage units to “on,” even those with zero power contribution. This ensures such devices can contribute to reactive power stability when solving power flow cases. In renewable redispatch, GridView does not preserve priority across units of the same power plant.

   To address these challenges, the study team prepared a Python-based script to redispatch VRE including solar, wind, and battery storage. The script applies the same procedure adopted for redispatching hydropower with slight modifications. It properly maps VRE between the GridView and power flow cases prior to redispatching. For each renewable power plant, the script computes the total generation by aggregating the generated power of all units from the GridView results. It then splits the computed total generation equally across all corresponding units for the corresponding renewable power plant in the power flow case.

3. **Make system-specific modifications:** Some components require special handling between the GridView and power flow models. In the Western Interconnection model, a few more issues required external intervention. These methods are described next.

   - *HVDC transmission lines:* The study team modeled HVDC lines as generators in power flow cases. Two generators, a sending terminal, and a receiving terminal replace each HVDC line. The real power of the generator at the sending terminal corresponds to the power flow injected into the HVDC line. In other words, the generator at the sending terminal will have a negative real power value. On the other hand, the real power of the generator at the receiving terminal corresponds to the amount of power flow from the HVDC line to the rest of the network. The direction of the power flow on the HVDC link determines the sending and receiving terminals. Figure A-13 illustrates the conversion of an HVDC line to two generators.

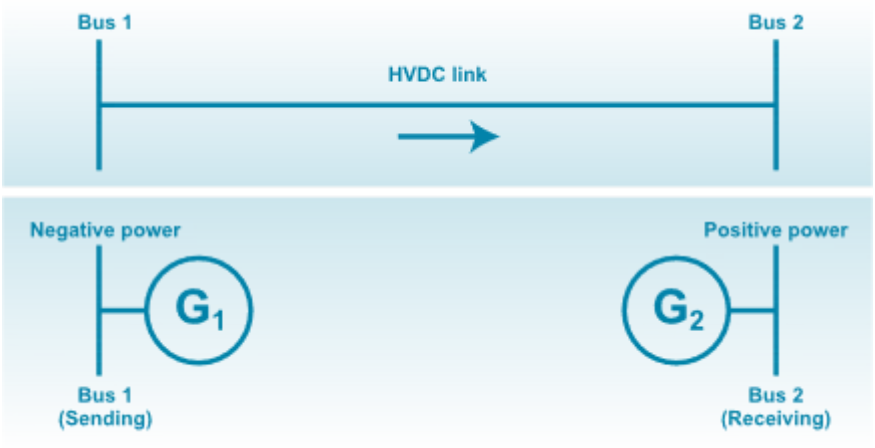


Figure A-13. Conversion of an HVDC line to two generators, a sending terminal, and a receiving terminal

- *Generator IDs:* After completing the previously mentioned processes, it is found at several buses the same generator is identified by a different ID in PF and PCM. This creates an issue when passing the data to the Chronological AC Power Flow Automated Generation (C-PAGE) platform to prepare the power flow cases. It is essential to ensure this data discrepancy is handled properly during the data processing.
- *Nuclear power plant:* The study team aggregated multiple steam turbine (ST)-nuclear generators at a single bus as a single ST-nuclear power plant and lumped them as a carbon-free nuclear generator at a nearby bus into the power flow model.

# Appendix B. Procedure for Preparing AC Power Flows Based on Production Cost Model Data for Power Flow Case Creation

There are some differences between direct current (DC) and alternating current (AC) power flow modeling. Because the production cost model (PCM) employs a DC model and linear solver, the study team did not consider the bus voltages in the initial stage of the optimization procedure. The system loss is another element that has an impact on the solution. Unlike AC power flows, where the loss is calculated as part of the power flow solution, a production cost model estimates the loss and adds it to the load. In addition, solving the chronological power flow models requires assumptions regarding the reactive power load and generation because the production cost model neglects them but the AC power flow does not. The research team used a reference power flow case to determine load distribution factors once, and then they applied those factors to all hours. Though this is acceptable in a production cost model because bus voltages are not considered, it is typically not the case in an AC power flow model because of the significant seasonal differences in the bus load distribution and voltage profiles.

Another significant distinction is the production cost model data do not include information concerning the reactive power dispatch of generators. In a power system, the solution for the power flow traditionally determines the actual reactive power dispatch of generators. The starting point for power flow algorithms such as the Newton–Raphson method is either a flat start or the operational point of a converged power flow case. Obtaining convergence for the power flow in a large-scale power system, such as the Western Interconnection, is difficult. It is challenging from the perspective of the power system to develop a dispatch for each generator that offers adequate reactive power while preserving a stable voltage profile for all buses in the system. Mathematically, the power flow in a system of this size is typically unconditioned, meaning a small change in demand can result in a large change in the system's state or voltage profile. Therefore, if the solution of the prior converged power flow case is far from the solution of the present power flow case, using a flat start or the solution of that case may be inefficient. Furthermore, if voltage violations occur on multiple buses, the algorithm is likely to converge to an unstable solution. This makes it difficult to import production cost model data and solve the chronological AC power flow problem.

Creating a basic converged AC power flow case normally takes a few hours to days because it involves production cost modeling, convergence of the AC power flow, and reactive power planning. With the use of the Chronological AC Power Flow Automated Generation (C-PAGE) tool created in the NTP Study, any large, interconnected system—including the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas (ERCOT)—may produce a converged AC power flow automatically and in a matter of minutes.

This modeling activity evaluated the engineering feasibility of a future system scenario. Although the study team used the same tools transmission planners use to test safe and reliable operations for future grid expansions, the full and large scope of contingency analyses transmission planners customarily perform was not applied. Given the significant numbers of power flow models available for analysis, the study team focused on smaller sets of contingencies that represent the most critical and impactful issues recognized by the transmission planning community. This is because of the large number of power flow scenarios that must be examined. The technical review committee (TRC) discussed the prioritization of contingency cases for exploration.

The Pacific Northwest National Laboratory (PNNL)-developed C-PAGE tool translated the production cost model outputs of selected operating conditional cases to AC power flow models. C-PAGE uses a three-stage process to translate datasets between the production cost and power flow models.

## B.1 Stage 1: Data Mapping and Model Validation of the Production Cost Model and Power Flow Cases

### B.1.1 System topologies of the production cost and power flow models

A seamless transition from production cost model simulation findings to power flow instances is necessary for transmission design studies. Therefore, it is important to understand how the production cost model results are exported to a power flow case, how to validate the process of updating the production cost model results to the power flow case, and the similarities and differences between the production cost model and power flow model. Consistency between production cost and power flow model system topologies is required to correctly feed the production cost model dispatch to power flow models, necessitating rectifying any differences. For example, any transmission lines in the two models must have a one-to-one match for transmission line identification (ID), status, and rating.

### B.1.2 Exporting production cost model simulation results to the power flow case

The C-PAGE produces nodal-level updates to the power flow model after receiving the results of the production cost model simulation. The unit commitment and economic dispatch for generation units, high-voltage direct current (HVDC) dispatch, transformer phase angles, and transmission line status are all provided to all equipment. A power plant in a production cost model is comparable to one or more distinct units in the power flow situation, as mentioned in Appendix A. The state of each of these units is comparable to that of the power plant in the production cost model result when the results are exported to a power flow case. Figure B-1 depicts the process of disaggregating generation and load from the power plant and balancing authority (BA) levels to the nodal level. Appendix A.2 details the production cost model postprocessing redispatch procedure.

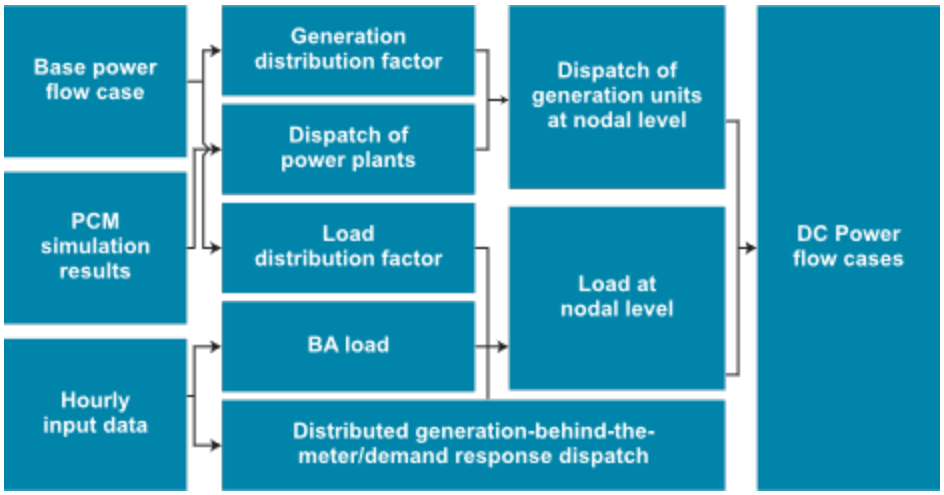


Figure B-1. Process of disaggregating generation and load from the production cost model simulation results to power flow cases

## B.2 Stage 2: DC-to-AC Convergence Process

The approach begins with Step 1 in Figure B-2, which updates the new production cost model result to a converged AC power flow case derived from the preceding timestep. The reasoning is the loading conditions for two consecutive power flow instances are frequently near one another; therefore, the voltage of the prior timestep in the converged AC power flow case is a useful starting point for solving for the power flow in the new power flow case.

Because the production cost model employs a DC power flow, the total generation equals the total load in the new power flow condition. In this approach, it is assumed the dispatch of all generation units—including the unit at the slack bus—is fixed, as in the production cost model results. Therefore, when converting from a DC power flow scenario to an AC power flow scenario, decreasing the nodal loads accounts for transmission losses.

As a result, Step 2 of the process progressively reduces the nodal loads prior to solving for the AC power flow. This step reduces the load further if the power flow does not converge. If the power flow converges, this step compares the resulting real power generation $P_{slack}$ at the slack bus to $P^0_{slack}$ in the production cost model result. This step reduces the load further if the difference at iteration *k* exceeds a certain tolerance $\delta$; otherwise, the load-reducing process is complete. It is worth noting this step uses an adaptive step size $\mu^{k+1}$ at iteration (*k* + 1) based on the slack generation difference $\Delta^k$ at time *k* to iteratively lower the load as follows:

$$\mu^{k+1} = \Delta^k \sigma = \mid P^k_{slack} - P^0_{slack} \mid \sigma \,, \qquad \text{Eq. B-1}$$

where $\sigma$ is a constant coefficient.

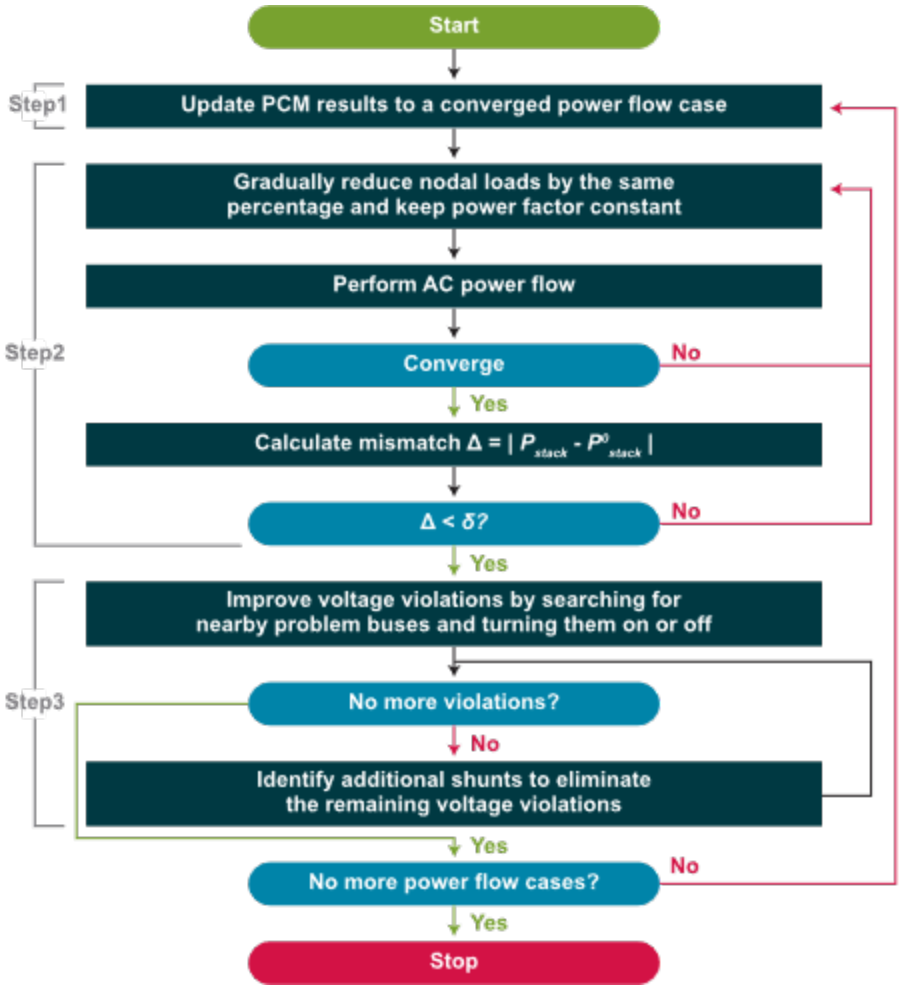


Figure B-2. Procedure to convert a converged DC power flow case from the production cost model results to a converged AC power flow case

## B.3 Stage 3: Reactive Power Planning for Voltage Improvement

After attaining a converged AC power flow situation, the focus moves to improving the bus voltage profile. Improving the voltage after attaining convergence of the AC power flow is critical because a good voltage profile at one timestep has a direct impact on the potential to achieve convergence of the AC power flow in succeeding timesteps. As a result, Step 3 in Figure B-2 examines all bus voltages to look for voltage violations. The next step is to process each bus that has a voltage violation and identify any current shunts on that bus or any surrounding buses. The level of voltage violation and the shunt step sizes determine whether to turn on, turn off, or change the dispatch of these shunt devices.

After a bus voltage violation is mitigated using the system's existing shunts, Step 3 checks for voltage violations again to discover any remaining violations. If a voltage violation is not completely rectified, this step performs another voltage improvement process based on a *Q-V* analysis to identify the locations and sizes of shunts to add to the system. The resulting power flow scenario is regarded as the final converged AC

power flow case for the current timestep after enhancing the voltage profile using existing and additional shunts. This step repeats the conversion of the DC power flow from the production cost model findings to a converged AC power flow case (Figure B-3) until all timesteps are processed.

Transition planning should include ample reactive power resources to meet reliability requirements under a wide variety of feasible contingencies. The reactive power is a critical reliability service for bulk power systems. Generators, capacitors, transmission lines, and loads all contribute to its supply; transformers, loads, and transmission lines all use it. The reactive power and voltage magnitude are closely related. Ensuring voltage remains within a reasonable range is achievable with careful reactive power planning.

At Stage 2, the voltage profiles of each converged AC power flow case require mitigation to address any voltage breaches. C-PAGE can improve voltage profiles by performing a *Q*-*V* analysis, which displays the sensitivity and volatility of bus voltages with respect to reactive power injections or absorptions. As depicted in Figure B-3, the strategy is to gradually improve a voltage profile while using suitable reactive power support devices.

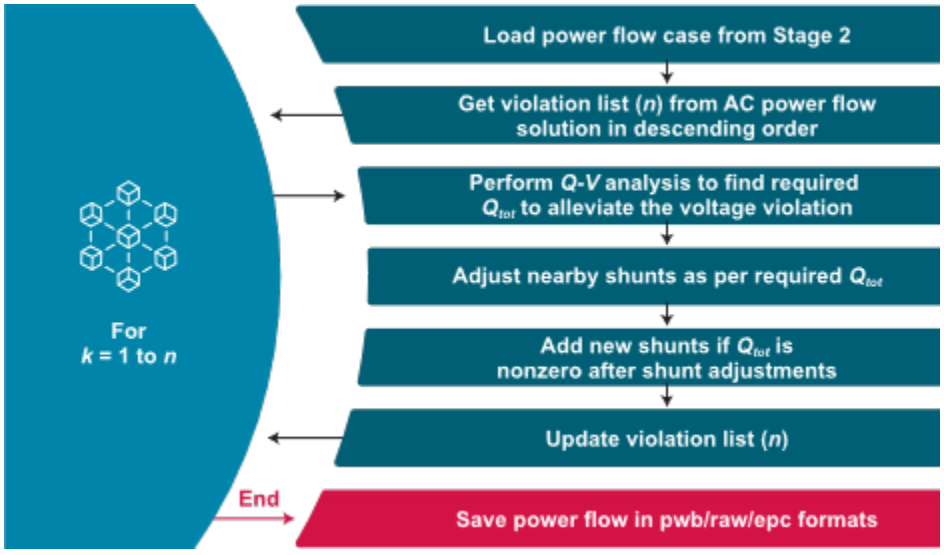


Figure B-3. Reactive power planning to improve voltage profiles

The reactive power planning algorithm starts by loading the power flow case from Stage 2 and extracting voltage-out-of-range violations for higher voltages. In this work, the focus is on base voltages of more than 230 kV, but the concept applies to any voltage level. The algorithm carries out a *Q*-*V* analysis of the bus with the highest voltage violation in the first stage to determine the necessary reactive power support ($Q_{tot}$) to reduce the voltage violation. This stage also involves sorting the violation list in descending order of voltage. If any shunts, such as capacitors or reactors, are found close to the bus being most violated, the simulator adjusts them to the needed $Q_{tot}$ value and updates $Q_{tot}$. The simulator inserts a new shunt if $Q_{tot}$ is still nonzero after the shunt changes. Then, it resolves the power flow and derives a list of violations. When the

simulator cannot converge at a specific transfer level throughout this process, that bus is skipped. If not, this procedure is repeated until there are no violations left on the list. With reasonable reactive power support devices, this algorithm incrementally improves a voltage profile, which can partially correct flow violations. Performing generation redispatch reduces power flow violations, but this was not done because the study team did not want to change the PCM generation dispatch at any time. Finally, the algorithm saves the power flow case with the better voltage profile in formats such as PowerWorld's pwb, PSS/E's raw, and PSLF's epc.

# Appendix C. Visualization of Simulation Results Using a Geographic Information System

## C.1 Introduction

For efficient analysis of the simulation results, there is a need for various graphs, including geographic information system (GIS)-based plots. Given the size of the generated dataset, the process of data processing, analysis, and visualization must be automated.

The use of QGIS in conjunction with the Python automation scripts enables advanced visualization and analysis of power flow results in the GIS domain. QGIS, an advanced open-source GIS platform, provides extensive tools for spatial data manipulation and visualization, efficient for representing electrical grid components and their operating conditions geographically. Integrating Python, a programming language with powerful libraries and scripting capabilities, enables the automation of complex data processing tasks. This integration facilitates the efficient handling of large-scale power flow datasets produced by production cost model, power flow, and contingency analysis tools—allowing the automated generation of detailed, interactive maps that display power flow information such as the transmission grid topography, voltage profiles, and transmission line loading. To achieve this goal, the study team implemented full back-to-back automation to extract power flow information from solvers (typically stored in binary files), process this information, and upload it to the database server, generating GIS visualizations (QGIS layers) and creating new, self-contained QGIS projects for specific power flow cases or scenarios.

## C.2 Features

Figure C-1 displays a flowchart of the visualization automation process. An on-premises server is used for simulation and data extraction. Subsequently, the process uploads the information to an AWS cloud-hosted PostgreSQL database server, which also incorporates GIS infrastructure information. A script to automatically generate a QGIS project and visualize the results is executable on a user's workstation computer. The following subsections provide more details about each block in the flowchart.

### C.2.1 Simulation and data extraction

An on-premises server hosts simulation applications (such as DCAT, PowerWorld, and GridView) and stores their outputs as binary files. It is crucial to eliminate redundancies and convert key information from binary format files into a database. Therefore, the process designed to extract, process, and upload data plays a pivotal role in effective data management.

The developed data processing automation facilitates user-friendly access and aids in data-driven decision making and optimal data use, as shown in Figure C-1. The data extraction procedure entails parsing data sources using simulator application programming interfaces (APIs) such as SimAuto or PSSPY, consolidating and

organizing data spread across various systems, and subsequently uploading them into a centralized data repository, e.g., MongoDB or AWS S3, for enhanced secure storage.

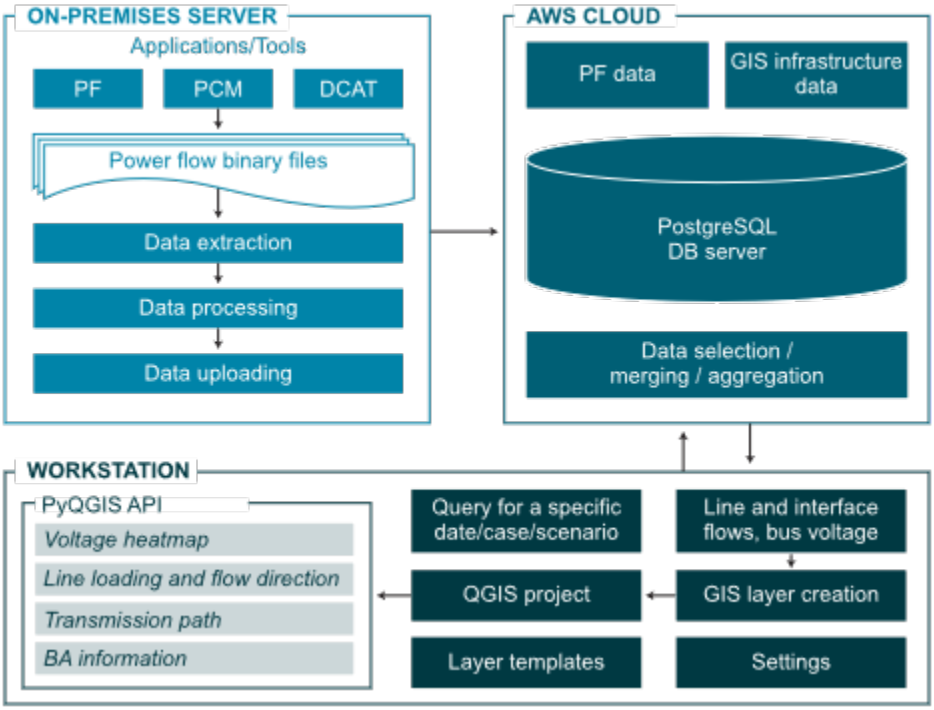


Figure C-1. Flowchart showing the automated process for analyzing and visualizing simulation results

### C.2.2 Cloud-based GIS database

The study team developed a cloud-based GIS database architecture to leverage the robust and scalable infrastructure provided by AWS cloud services. This architecture uses a PostgreSQL database, a sophisticated object-relational database system known for its robust data management capabilities.

To enhance the GIS functionality of the PostgreSQL database, the study team integrated the PostGIS add-in. PostGIS expands the capabilities of PostgreSQL to include support for geographic objects, enabling the execution of location-based queries in SQL. This enhancement is crucial for conducting spatial data analysis and for operations within GISs.

The study team sourced various publicly available and commercial GIS information regarding electricity infrastructure. This includes the locations of buses, lines, substations, power plants, and more, providing a comprehensive overview of the electrical grid's structure and components.

In addition, the database stored the simulation results from the production cost model, power flow, and contingency analyses and systematically indexed these results with specific identifiers such as scenario, case, and date, facilitating efficient data retrieval and organization.

The strength of the PostgreSQL database on AWS allows efficient data manipulation capabilities, enabling rapid data retrieval, aggregation, and the merging of datasets (e.g., joining power flow data with bus locations).

### C.2.3 QGIS visualization

The study team designed a user-centric and interactive power flow analysis visualization that is executable using a Python script from any workstation machine. The user must specify input parameters in a settings file, which includes the date, case, scenario, and the type of basemap desired (such as a geographical map, satellite map, or gray/dark map). With these inputs configured, the user executes the Python script, which queries the database based on the user's specified criteria. The server processes this query and returns the required power flow information, such as line flows, bus voltages, and interface flows—all linked with their respective location data.

Once the relevant data are retrieved, the script uses PyQGIS, the Python API for QGIS, to create QGIS layers. It applies predesigned QGIS layer templates to the data, enabling the visualization of flows as arrows showing directions. They also vary in color and width to represent different flow sizes and line loadings relative to their limits. The script further enhances the visual representation by generating a voltage heatmap using the inverse distance weighting (IDW) method. This method provides a graphical representation of voltage levels across the network. IDW, a type of deterministic method for spatial interpolation, assigns values to unknown points based on the values of known points, weighted by the inverse of their distance. This function is available in the Geospatial Data Abstraction Library (GDAL), which is part of the QGIS package. The created heatmap is a raster layer and uploaded to the server using the pg_raster_upload plugin. To improve visualization, the study team added some layers to the project such as balancing authority (BA) boundaries, state boundaries, and major cities.

Finally, the script compiles all the elements into a QGIS project, which is then saved for subsequent use. QGIS can open the resulting project, where users can interact with the map, zooming in on areas of interest and gaining insights through the visual representation of the system's operating conditions.

## C.3 Visualization Examples

Figure C-2 presents an example of voltage profile visualization using a heatmap along with the power flows through the transmission lines. It also depicts the borders of U.S. states and major cities. The inclusion of U.S. state borders and major cities in the visualization adds a geographical context, enabling viewers to understand the physical locations of infrastructure elements. Figure C-3 provides another example visualization of simulation results, illustrating the power flows in the grid, the loading of major Western Interconnection paths, and the boundaries of the BAs.

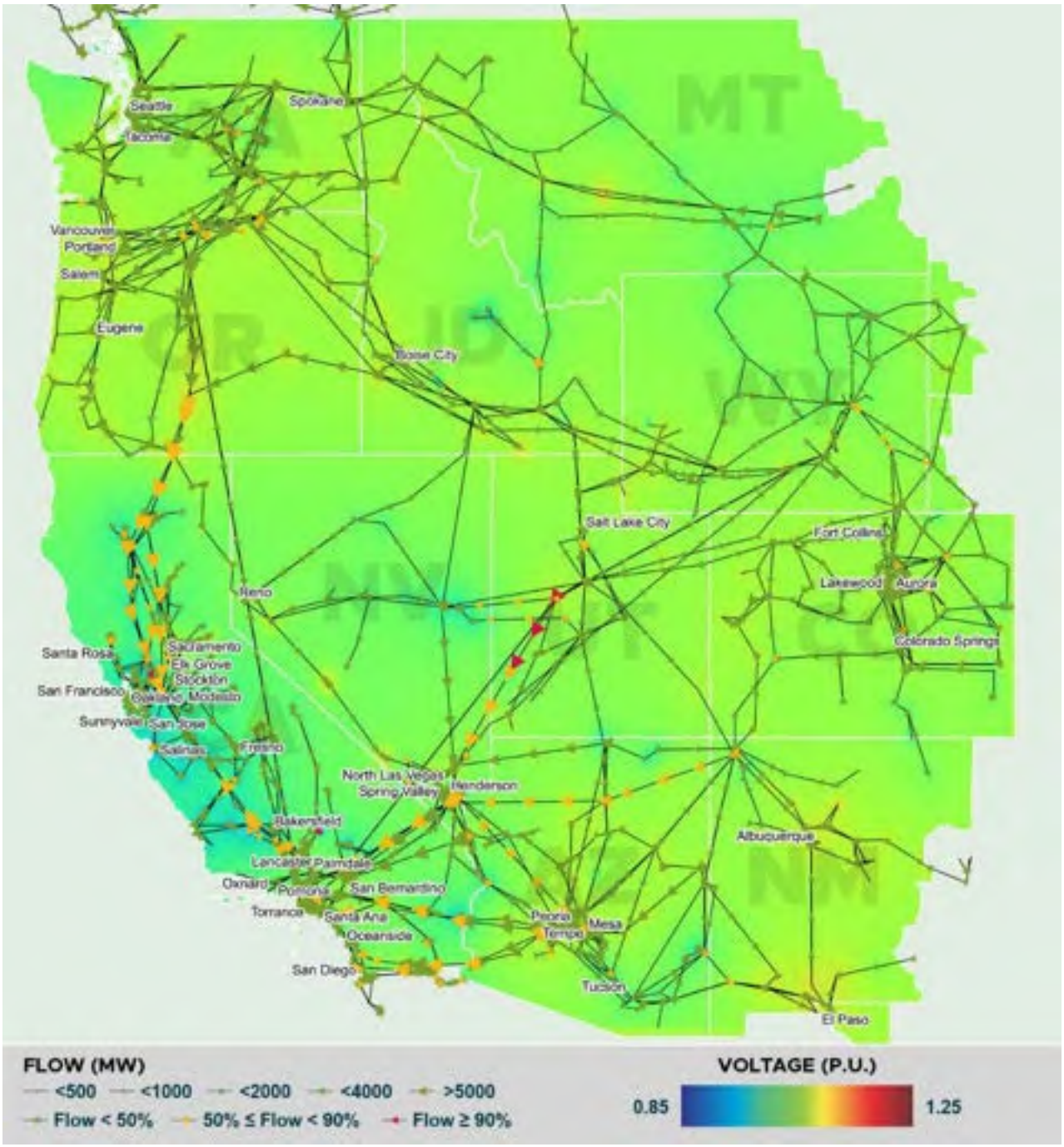


Figure C-2. Voltage heatmap and visualization of the transmission line flows

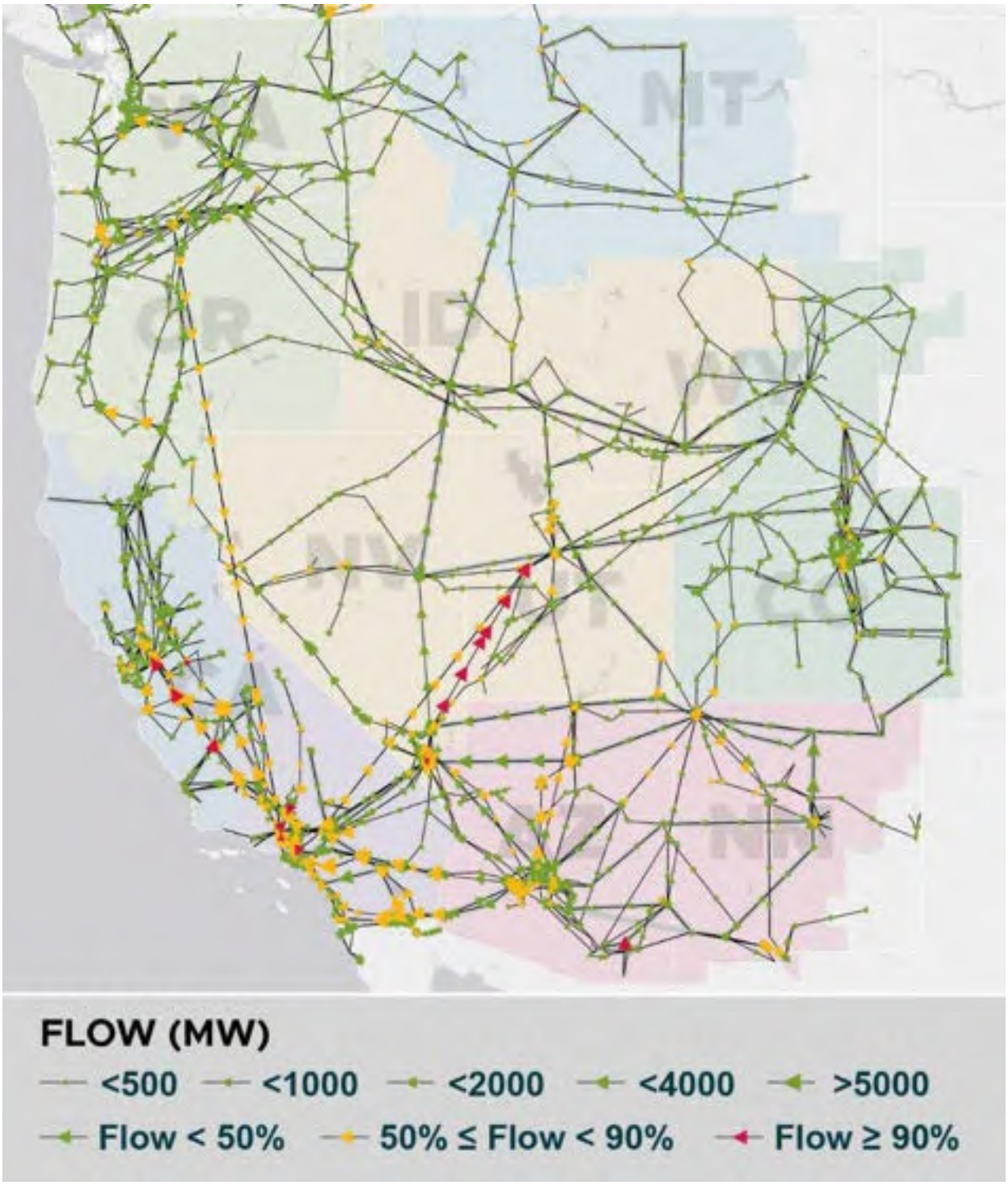


Figure C-3. Visualization of the major loading paths and transmission line flows

# Appendix D. Western Interconnection Transmission Modeling Assumptions

For the fixed shunt line reactors of new lines (new corridors only; not for duplicates of existing ones), the study team made the following assumptions for shunt compensation:

- Total fixed line compensation:
  - Length < 100 kilometers (km) – 0% of the line susceptance
  - 100 km ≤ length < 150 km – 40% of the line susceptance
  - 150 km ≤ length < 200 km – 45% of the line susceptance
  - Length ≥ 200 km – 50% of the line susceptance
- Distribution of the fixed line compensation:
  - 50% of the total fixed shunt compensation at the “from” terminal
  - 50% of the total fixed shunt compensation at the “to” terminals.

DOE/GO-102024-6260 | October 2024

# National Transmission Planning Study

## Chapter 5:

# Stress Analysis for 2035 Scenarios

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

This report is being disseminated by the Department of Energy. As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Public Law 106-554) and information quality guidelines issued by the Department of Energy.

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# Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios (this chapter)** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# List of Acronyms

| | |
|---|---|
| AC | alternating current |
| ADS | Anchor Dataset |
| B2H | Boardman to Hemingway |
| BA | balancing authority |
| BESS | Battery Energy Storage Systems |
| CA | California |
| CAISO | California Independent System Operator |
| CIPB | Pacific Gas & Electric Bay Area |
| CIPV | Pacific Gas & Electric Valley Area |
| CISC | Southern California Edison |
| CISD | San Diego Gas & Electric |
| C-VOLL | cumulative value of lost load ($) |
| DC | direct current |
| DOE | U.S. Department of Energy |
| EIA | Energy Information Administration |
| ES | energy storage |
| FERC | Federal Energy Regulatory Commission |
| GODEEEP | Grid Operations, Decarbonization, Environmental, and Energy Equity Platform |
| GT | gas turbine |
| HTC | hydrothermal coordination |
| HVDC | high-voltage direct current |
| ICE | interruption cost estimate |

| | |
|---|---|
| IPCO | Idaho Power Company |
| IPFE | Far East (Idaho Power) |
| IPMV | Magic Valley (Idaho Power) |
| IPTV | Treasure Valley (Idaho Power) |
| IM3 | Integrated Multisector Multiscale Modeling |
| km | kilometer |
| kV | kilovolt |
| kWh | kilowatt-hour |
| LSE | load-serving entity |
| M | meter |
| ML | machine learning |
| MLP | multilayered perceptron |
| MT | multiterminal |
| MW | megawatt |
| MWh | megawatt-hour |
| NERSC | National Energy Research Scientific Computing Center |
| NEVP | Nevada Power |
| NG | natural gas |
| NOB | Nevada–Oregon Border |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| O&M | operations and maintenance |
| PACE | PacifiCorp East |
| PAID | PacifiCorp East - Idaho |

| | |
|---|---|
| PAUT | PacifiCorp East - Utah |
| PAWY | PacifiCorp East - Wyoming |
| PCM | production cost model |
| PHS | pumped hydro storage |
| PNNL | Pacific Northwest National Laboratory |
| PNW | Pacific Northwest |
| PV | photovoltaic |
| RCP | representative concentration pathway |
| ReEDS | Regional Energy Deployment System (model) |
| reV | Renewable Energy Potential (model) |
| SAM | System Advisor Model |
| SPCC | Sierra Pacific Power |
| TELL | total electricity loads |
| TGW | thermodynamic global warming |
| TWh | terawatt-hour |
| UTC | Coordinated Universal Time |
| VEA | Valley Electric Association |
| VOLL | value of lost load ($/kWh) |
| WECC | Western Electricity Coordinating Council |
| WRF | Weather Research and Forecasting |

# Chapter 5 Overview

This chapter presents the study's extreme stress analysis methods and key findings. *Extreme stress* refers to extreme meteorological events such as heatwaves and droughts that can affect grid operations. *Extreme stress analysis* assesses the potential impacts of such meteorological extremes on bulk power systems' reliability and operations. The study used a suite of modeling tools to project extreme events onto future grid scenarios to assess the reliability, economic, and operational impacts of stress conditions under different transmission expansion options. The goal was to analyze how the different transmission planning frameworks influenced grid operations throughout periods of heightened stress and which strategies successfully maintained grid operations. Findings from this extreme stress analysis provide initial regional insights into how grid operations may respond to extreme events based on different transmission characteristics, and the stress analysis approach is offered as a proof-of-concept model for future resource adequacy analyses and transmission planning processes that consider grid reliability under extreme weather scenarios.

The study applied its stress analysis method to two nodal transmission expansion scenarios for the Western Interconnection for the year 2035. The analysis projects spatially defined heat and drought condition impacts on hourly load, wind, solar, and the availability of hydropower during droughts and reveals how extreme events challenge reliable grid operations as regional loads are increased during the heat event while supply decreased because of hydropower reductions. The two nodal transmission scenarios are: 1) the western interconnection 2035 Limited (Lim) scenario and 2) the western interconnection 2035 Alternating Current (AC) scenario.[2] The specific assumptions used for these scenarios are high demand growth[3] and the 90% decarbonization by 2035 emissions constraint.

Four stress cases were defined based on historical events in the West using production cost simulations for the year 2035 for both nodal transmission scenarios to generate 8 simulation results (4 stress cases × 2 scenarios; see Table I). The acronyms "AC" and "Lim" denote the Alternating Current and Limited transmission scenarios, respectively, and "H" and "H+D" represent the heatwave and the combined heatwave and drought events, respectively.

[2] The stress analysis study examined only the Lim and AC scenarios within the Western Interconnection footprint because of study timeline limitations. Future areas recommended for study include conducting additional stress analyses for combined Eastern and Western Interconnection scenarios and expanding the range of threats (e.g., cold snaps) and transmission expansion scenarios (e.g., multiterminal high-voltage direct current [HVDC]).

[3] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

Table I. Stress Case Scenarios

| Stress Case | Stress Event |
|---|---|
| 1 | California Heatwave |
| 2 | California Heatwave + Pacific Northwest Drought |
| 3 | Pacific Northwest Heatwave |
| 4 | Pacific Northwest Heatwave + Pacific Northwest Drought |

## Key Findings

1. **Compounded extreme events lead to higher levels of unserved energy than individual events.** When the California (CA) or Pacific Northwest (PNW) heatwave is combined with the PNW hydropower drought, the resulting unserved energy increases in both regions and across both transmission scenarios (Figure I).

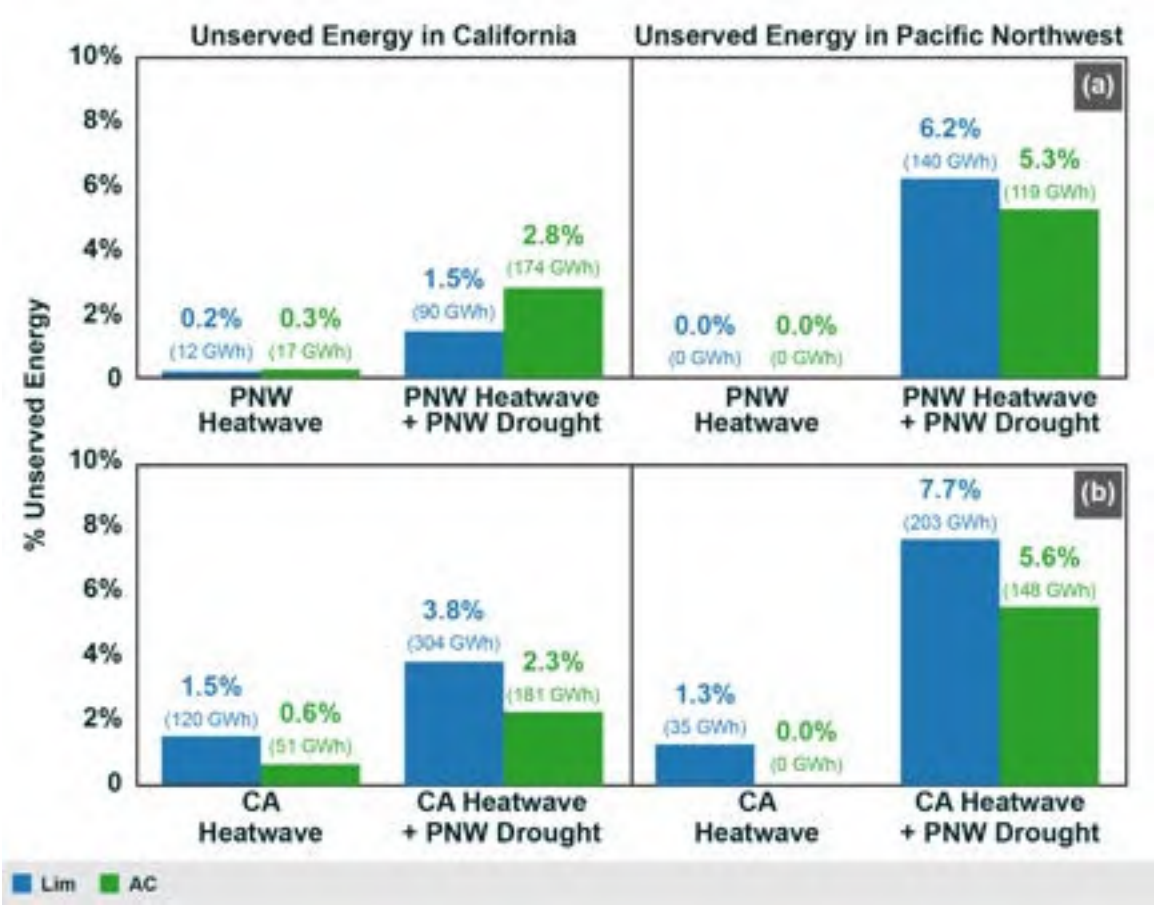


Figure I. Both Lim and AC scenarios show pronounced effects from the combination of a heatwave in (a) the PNW or (b) California and the PNW drought compared to the respective single heatwave events

*GWh = gigawatt-hour*

2. **The buildout of interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of unserved energy.[4]**
   The new interregional capacity (in the AC scenario) within the Western Interconnection region forges a vital corridor for channeling wind resources from New Mexico, Colorado, and Wyoming to meet California's increased demand during the California heatwave and PNW drought. This transmission route is vital to address California's surging demand and compensating for hydropower shortfalls in the PNW (Figure II). As a result, unserved energy is reduced by 1.5% in California (4.2% in Southern California) and 1.9% in the PNW in the AC scenario compared to the Limited scenario.

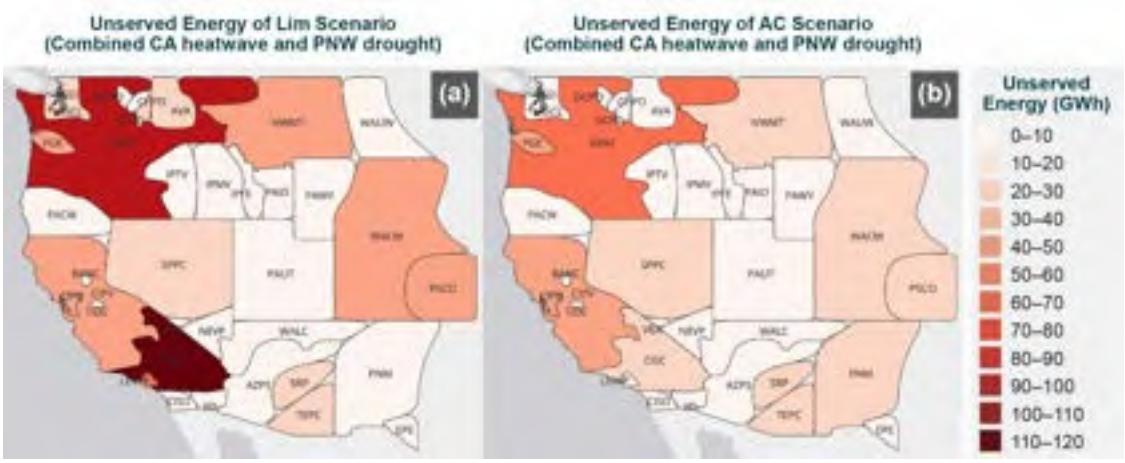


Figure II. The AC scenario (b) significantly reduces the worst regional impacts of combined California heatwave and PNW drought events (the most severe of the stress cases modeled) relative to the Lim scenario (a)

3. **Transmission and resource planners should carefully consider interregional transmission capacity and additional local generation capacity to minimize the risks of extreme stress events.** Both interregional transmission and local generation capacity expansion are needed to manage risk during a variety of extreme stress events, as exemplified by the combined heatwave and drought in the PNW. California reported 1.3% lower unserved energy levels in the Limited scenario than the AC scenario (Figure III), benefiting from its greater installed capacity of local dispatchable resources (such as battery storage and natural gas) (Figure IV) that could support the state's increased load demands amid decreased imports from the PNW. In both scenarios, California is a net exporter, supporting the PNW heatwave and drought.

   This specific case highlights that the attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation availability differently,

[4] Unserved energy is the amount of customer demand that cannot be supplied due to a shortage of available generation resources.

including the ability to transfer power between regions. Hence, depending on the extreme event under study, a system with different levels of interregional transmission capacity may respond differently based on the levels and types of generation and storage resources, including local assets. Therefore, transmission planning solutions will need to carefully consider the attributes of extreme events and how those affect generation availability and transmission utilization.

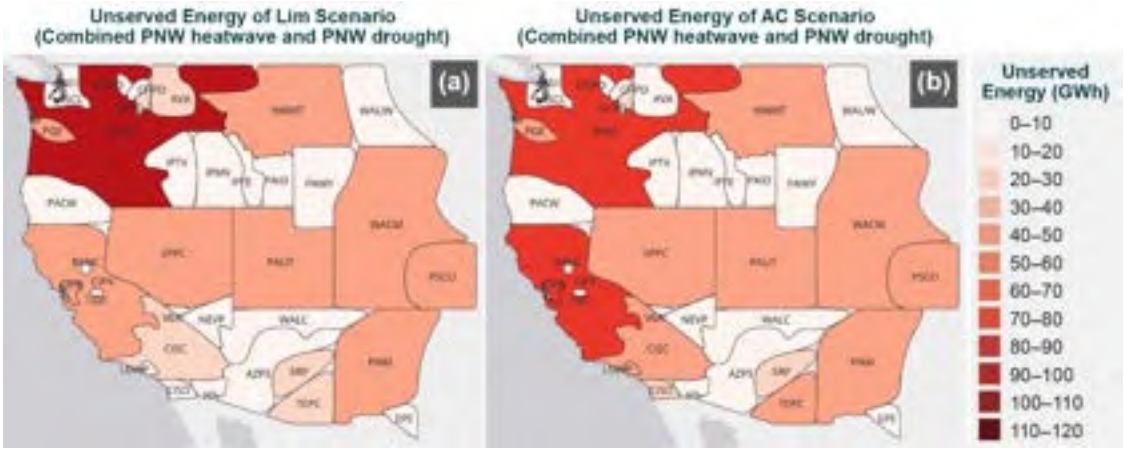


Figure III. In the Lim scenario (a), the greater installed capacity of battery energy storage resources and natural gas turbines in California leads to a 1.3% reduction in unserved energy in California compared to the AC scenario (b)

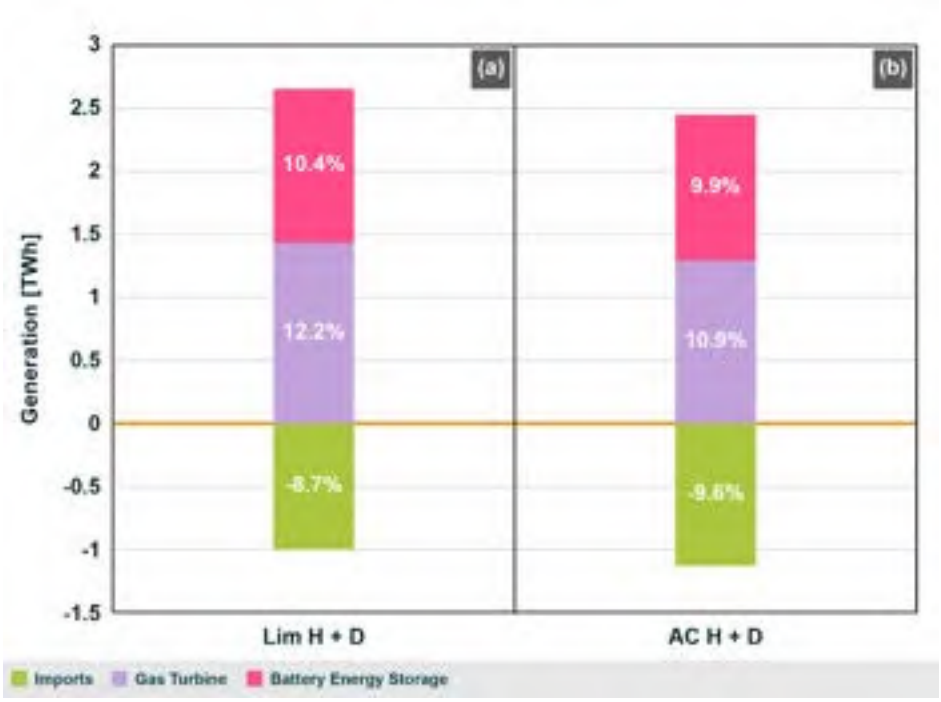


Figure IV. Generation outputs (terawatt-hour [TWh]) in California for the Lim (a) and AC (b) scenarios during the combined PNW heatwave event with PNW drought

*In the Lim scenario, there is a greater dispatch of battery energy storage and natural gas turbines, leading to reduced unserved energy in California compared to the AC scenario*

4. **The unserved energy peaks in the morning are because of low online energy resource availability and increasing load ramps.** The unserved energy peak coincides with increasing morning load ramp[5] and exhausted battery and pumped hydro energy storage resources (because of the full use of storage to meet the peak load in the late afternoon when solar diminishes), prior to solar generation coming online. The amount of unserved energy is higher in the Lim scenario compared to that in the AC scenario (Figure V), underscoring the importance of interregional capacity (in the AC scenario) in boosting California imports to meet the load during early morning hours.

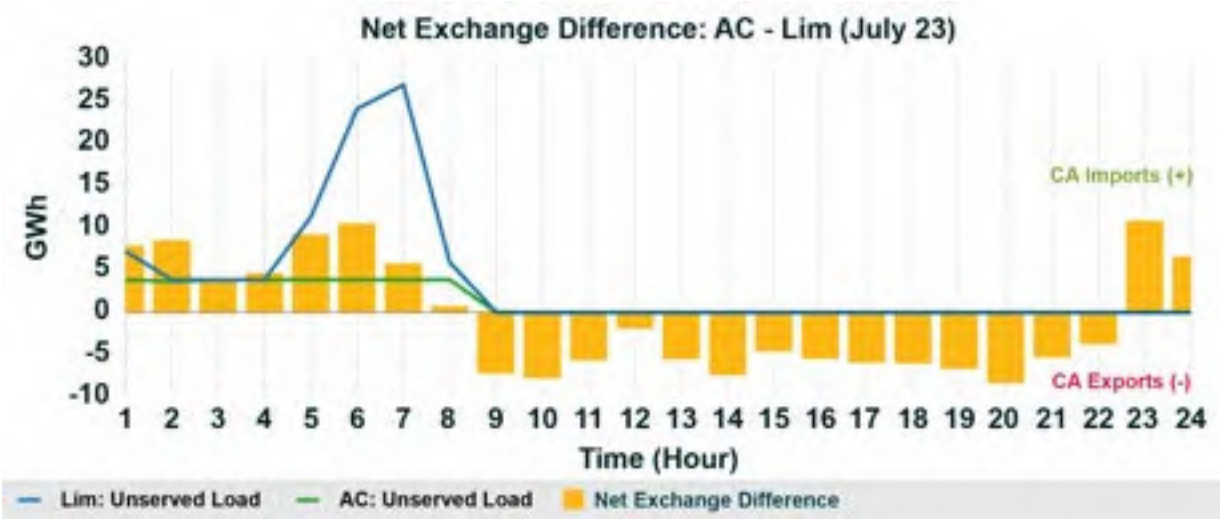


Figure V. Hourly unserved energy during the combined California heatwave and PNW drought; the yellow bars show the hourly net exchange difference between the AC and Lim scenarios, highlighting the interregional support (in the AC scenario) to California (+) during those morning hours

5. **Different transmission topologies provide varying economic benefits of reliability based on extreme event locations and types.** The study revealed the reliability benefits of different transmission topologies are highly dependent on geographic location and stress intensity. The NTP Study estimated economic benefits based on four stress events (PNW heatwave, PNW heatwave with PNW drought, California heatwave, California heatwave with PNW drought), and the transmission topology with greater benefits depends on the location and intensity of the modeled event. Future work should combine estimates of the benefits of preventing outages during extreme events with the probability of event occurrence to obtain expected benefits that can be used to augment a cost-benefit analysis.

[5] Morning load ramp is defined as the transition from relatively lower loads to higher loads in the morning.

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# 1 Introduction and Background

This section describes the stress analysis of specific transmission expansion scenarios developed for the Western Interconnection in support of the National Transmission Planning Study (NTP Study):

1. **Western Interconnection 2035 Limited (Lim) Scenario**
   Transmission is only developed within Federal Energy Regulatory Commission (FERC) Order No.1000 planning regions; no interregional transmission is included.

2. **Western Interconnection 2035 Alternating Current (AC) Scenario**
   Transmission is developed between adjacent FERC Order No.1000 regions in the Western Interconnection; no transmission is built between the Western and Eastern Interconnections.

To understand the reliability and economic value of transmission expansion scenarios during extreme stress events, it is necessary to perform chronological hourly production cost simulations. These simulations offer insights into how different regions may withstand such events, given their unique generation mixes and transmission capacity. The interplay between these factors is critical, highlighting the importance of extreme stress analysis in understanding the potential benefits of expanding transmission infrastructure.

## 1.1 Linkage to Other NTP Chapters

This chapter builds on previous chapters of the NTP Study—particularly Chapters 2 and 3—by applying extreme stress events to the nodal transmission scenarios. The NTP Study derived the nodal transmission scenarios starting with the analysis of the zonal capacity results obtained from the capacity expansion model (Chapter 2). The study team then employed a zonal-to-nodal methodology (Chapter 3) to refine the zonal capacity results to a more granular nodal level. The zonal-to-nodal methodology results in two distinct nodal transmission scenarios for the year 2035: the Alternating Current (AC) scenario and the Limited (Lim) scenario.[6] The study team used production cost modeling to simulate these two nodal transmission scenarios under the same stress conditions, derived from a stress case modeling framework. This modeling framework uses a suite of modeling tools to simulate hourly load, wind, and solar time series under varying weather conditions and hydropower availability during droughts.

Figure 1 summarizes how the stress analysis framework referenced in this chapter is related to the initial datasets, capacity expansion modeling, and zonal-to-nodal realization found in other chapters.

[6] This chapter uses the nodal transmission scenarios based on the earlier Regional Energy Deployment System (ReEDS) scenarios (Round 1). For a brief description of the two nodal transmission scenarios, see Section 3 of this chapter. For a more comprehensive description, see Section 4 of Chapter 3.

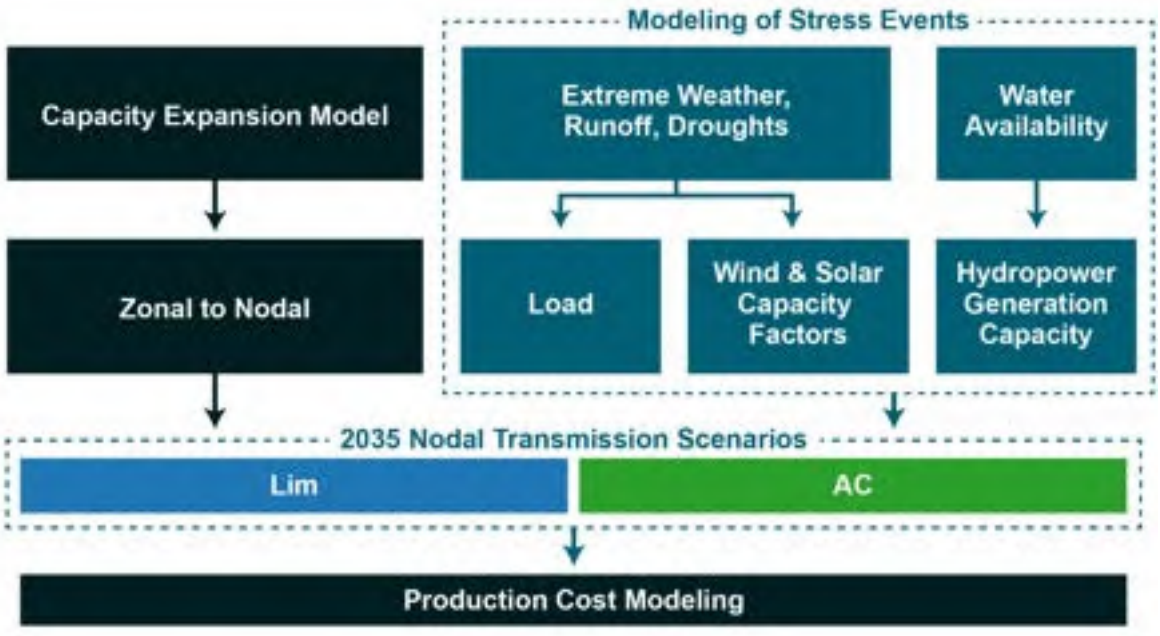


Figure 1. Modeling framework for the stress cases analyzed in the NTP Study

## 1.2 Motivation

In recent years, the power grid has increasingly faced significant challenges because of the rising frequency and intensity of extreme weather events. Concurrently, the ongoing transition to renewable energy sources—including wind and solar—alongside the increasing electrification of various sectors such as transportation and heating has introduced additional variability into the system. Recent developments, such as those related to climate change, underscore the importance of understanding how extreme conditions, whether occurring individually or in tandem (for example, extreme heat coupled with droughts), can have extensive effects on the grid. In this evolving landscape, new transmission capacity could play a crucial role in diversifying the generation mix in regions affected by extreme stress events by facilitating the transfer of energy from nonaffected regions.

Historically, entities could effectively manage and prepare for rare and mildly disruptive occurrences because they were fairly predictable in the short term with limited impacts. However, climate change effects coupled with increased urbanization and the aging transmission infrastructure have led to a significant increase in the likelihood of severe power system reliability incidents (Auffhammer, Bayliss, and Hausman 2017; Cohen et al. 2022; Do et al. 2023; Dyreson et al. 2022; Lee and Dessler 2022). Unlike before, when such events were isolated and affected only specific areas, these events now often happen concurrently and affect vast regions. An example of this is the simultaneous occurrence of severe droughts, wildfires, and a massive heatwave in the Pacific Northwest (PNW) in June 2021 (Balaraman 2021). Because these events are no longer exceptional or infrequent, power system planners and operators must gain a deeper understanding of how changing weather patterns interact with the modern electrical grid to mitigate the effects of these events.

Concentrating on heatwaves and droughts in the western United States, this chapter investigates 1) how extreme stress events exacerbate strain on the grid by simultaneously increasing demand while diminishing supply and 2) how the two NTP nodal transmission expansion scenarios (i.e., Lim and AC) perform under the influence of such events. In this context, the study team seeks to answer the following questions:

- If part of the Western Interconnection (shown later in Figure 14) experiences an extreme event that includes a simultaneous heatwave and drought, can the Western Interconnection grid avoid unserved energy?
- What is the role of new and existing transmission capacity during extreme stress events across the Western Interconnection?
- How can transmission capacity diversify the generation mix in regions affected by extreme climate events, and why is this diversification critical for highly decarbonized systems exposed to such events?

To address these questions, the study team employed production cost modeling to simulate power grid operations as well as weather-driven modeling tools to generate hourly load, wind, and solar time-series data under varying stress conditions and hydropower availability during droughts. Specifically, GridView—a production cost modeling tool developed by Hitachi Energy (2024)—was used to model the stress cases. GridView is a chronological unit commitment and economic dispatch model that minimizes power systems' operating costs to meet electricity demand and reserve requirements while satisfying various operating constraints. These constraints include unit-specific limitations (such as maximum/minimum capacity limits, minimum up- and downtimes, and ramping limits) as well as systemwide constraints (such as transmission line capacity limits, interface capacity limits, operating reserves, emission constraints, and hurdle rates). Operating costs largely consist of fuel costs, variable operating and maintenance costs, and startup/shutdown costs. The study team imported load, wind, and solar time-series and hydropower energy into GridView to simulate the evolution of the electricity supply and demand during extreme events.

# 2 Brief Methodology and Datasets

## 2.1 Types of Threats

This section describes the two types of threats: single- and multievent threats (where two or more weather events coincide).[7] The selected threats are 1) continental heatwaves[8] and 2) combined heatwaves and drought conditions, which are expected to affect the grid in several ways—including hourly load, generation, and water availability, which in turn will affect hydropower generation.

Heatwaves affect the grid by simultaneously increasing the demand for electricity (primarily because of increased demand for space cooling) and reducing supply through the derating of generators and derating transmission capacity (Auffhammer, Bayliss, and Hausman 2017; Sathaye et al. 2013; Bartos et al. 2016). Because they tend to be spatially widespread, heatwaves affect vast regions of the electric grid simultaneously (Sundar et al. 2023), which in turn limits the power grid's ability to alleviate stress during extreme heatwave events. Combined heatwave and drought events can lead to significant generation shortfall risks (Turner et al. 2019).

Solar generation is affected by heatwaves because the efficiency of solar panels decreases as the temperature increases. The exact change in efficiency depends on the panel type but ranges from −0.36%/°F to −0.85%/°F (Dobos 2014). For example, a 45°F above-average heatwave would cause a reduction in efficiency of 4%–9.4%, depending on the panel. Wind generation is affected by heatwaves as well, but the effects are meteorologically and regionally dependent. For example, heat domes are a meteorological phenomenon known to cause extreme heat and suppress wind (White et al. 2023). Not all extreme heat is caused by heat domes, and the wind response during extreme heat can vary widely, depending on the region and the meteorological conditions.

Hydropower generation can be both directly and indirectly affected by heatwaves. Extreme heat can cause unexpected snow melt, increased evaporation losses, increases in stream temperature, and increased load, which necessitate changes in hydropower operations. That said, hydropower is typically resilient to short-term heatwaves. In general, drought conditions lead to a regional decrease in hydropower availability, but systemwide in the Western Interconnection, hydropower is remarkably consistent year to year (PNNL 2022). Heatwaves combined with drought conditions can stress specific hydropower facilities even further—even if the effect is buffered at the Western Interconnection-wide scale.

[7] This chapter focuses only on two types of threats applied to two considered transmission expansion scenarios (Limited and AC). Future work would include expanding the range of threats (e.g., cold snaps) and transmission scenarios (e.g., multiterminal [MT] high-voltage direct current [HVDC]).
[8] A heatwave event is defined as a period of abnormally hot weather generally lasting more than 2 days. They can cover a large area, exposing a high number of people to hazardous heat.

### 2.1.1 Continental heatwaves

The study team selected two exemplar case studies: two unique and contrasting historic western U.S. heatwave events. The first occurred for approximately 8 days from roughly June 25, 2015, to July 2, 2015, and covered most of the western United States, including the PNW (Figure 2). The second occurred for approximately 7 days from roughly July 22, 2018, to July 28, 2018, and was most intensive over California and the Desert Southwest (Figure 3). The study team used a unique thermodynamic global warming approach to explore how these two heatwave events may be modified under climate change (Jones 2023). Choosing two heatwaves with different spatial representations allowed the study team to test the ability of expanded transmission to alleviate regional versus widespread stress events.

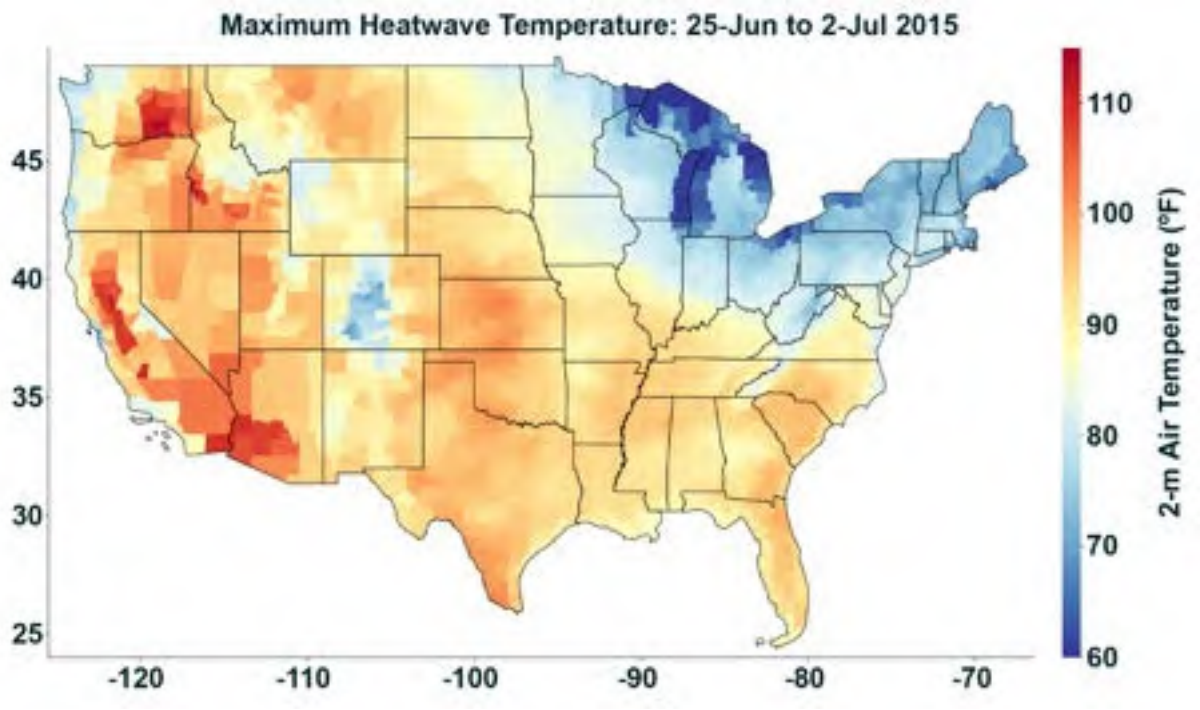


Figure 2. 2015 heatwave event in the PNW

*Temperatures in eastern Washington exceeded 112°F during this event. Well above average temperatures extended across much of the West.*

*m = meter*

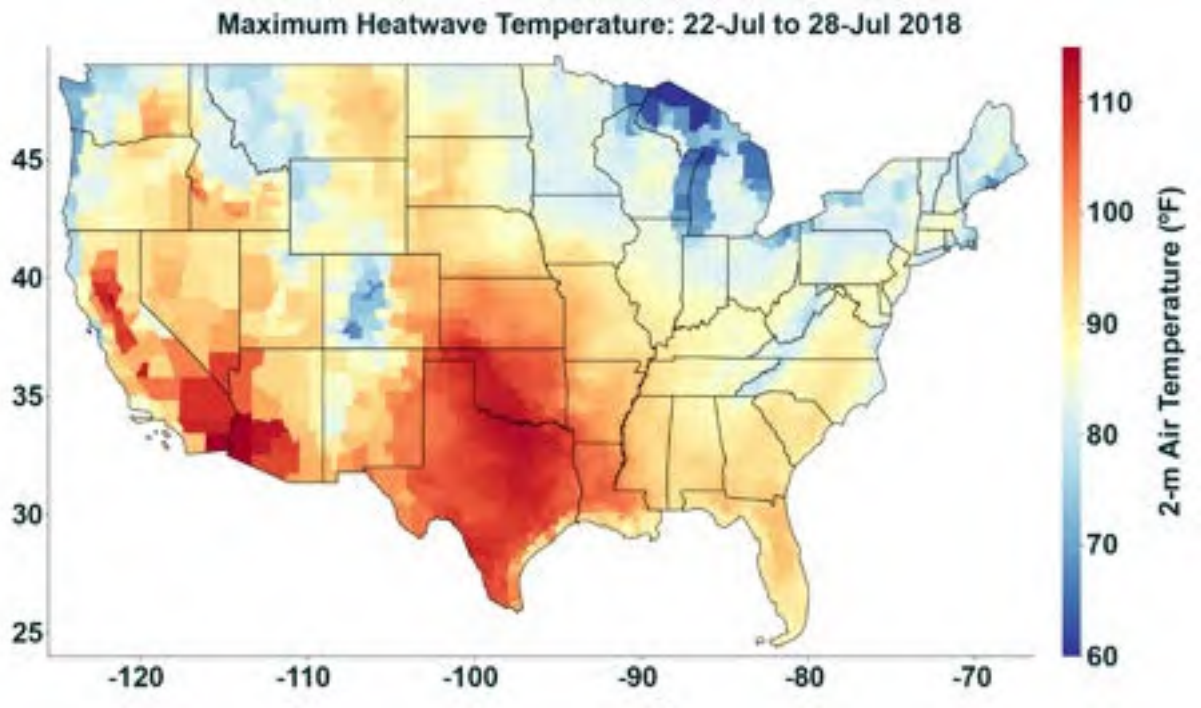


Figure 3. 2018 heatwave event in California and the Desert Southwest

*This event was more localized to the central California valley and Desert Southwest, where maximum temperatures exceeded 110°F.*

Figure 4 shows the evolution of the daily maximum temperature in the western United States from 2000 to 2019 (Jones et al. 2023). The blue and gray shading in the plot is used to show the timing and magnitude of the 2015 and 2018 heatwave events integrated into the NTP Study. The daily maximum temperatures during both events were 8–10°F above the historical average with slightly warmer values occurring during the 2018 event. In both events, there are only a small number of days in the historical record in which temperatures exceeded the values observed during the heatwaves evaluated in the NTP Study. These intentionally selected heatwaves broke daily temperature records in multiple places.

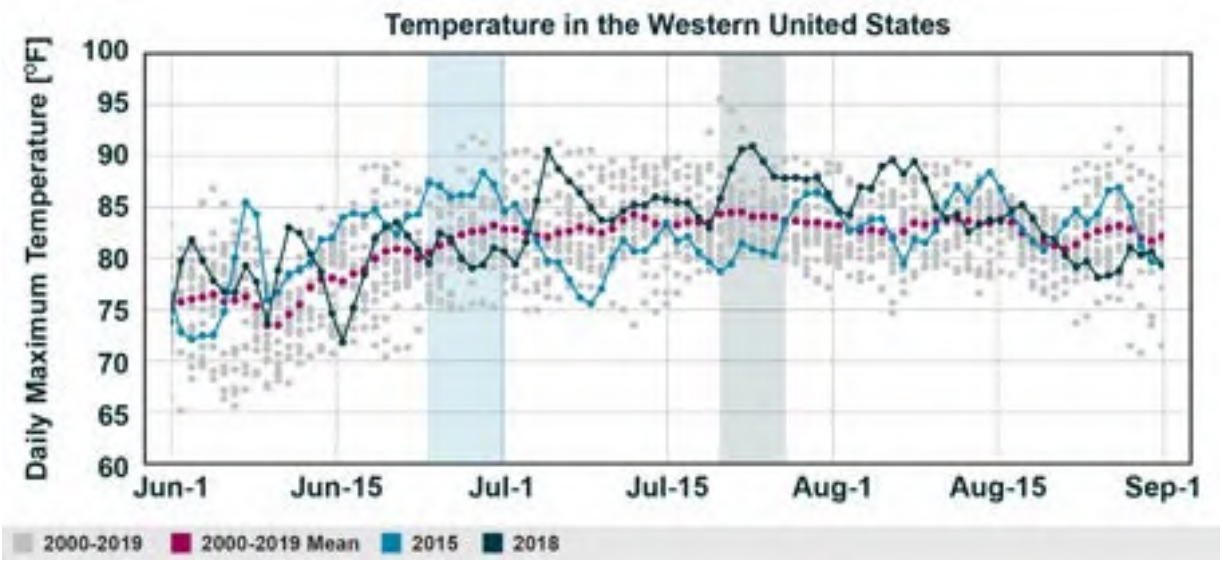


Figure 4. Evolution of the daily maximum population-weighted temperature in the western United States from June through August

*Each gray dot shows the daily maximum temperature in a sample year from 2000 to 2019. The magenta dots show the average maximum temperature from 2000 to 2019. The blue and black dots and lines show the evolution of the temperature in 2015 and 2018, respectively. The 2015 and 2018 NTP Study heatwave events are highlighted by the shaded blue and gray boxes, respectively.*

The study team acknowledges extreme stress events, particularly heatwaves, can affect the thermoelectric cooling capacity of thermal power generators such as coal and nuclear plants—potentially leading to a decrease in their power output. However, given thermal generation constitutes a small portion of the Western Interconnection generation mix in the two high-renewable transmission scenarios and considering the limited data available on plant-specific thermoelectric cooling technologies, the study team opted to disregard derates of thermal plants during extreme heat.

### 2.1.2 Hydropower droughts

To model drought, the study team used plant-level water availability information from the year 2001, which is one of the most severe summer droughts across the Western Interconnection over the past 20 years, shown in Figure 5 (Turner et al. 2022). The 2001 drought resulted in the Western Interconnection's worst year for hydropower generation, with total generation approximately 21% below the twenty-first century average. The year 2001 drought was particularly severe in the PNW, where about two-thirds of western hydropower capacity is located.

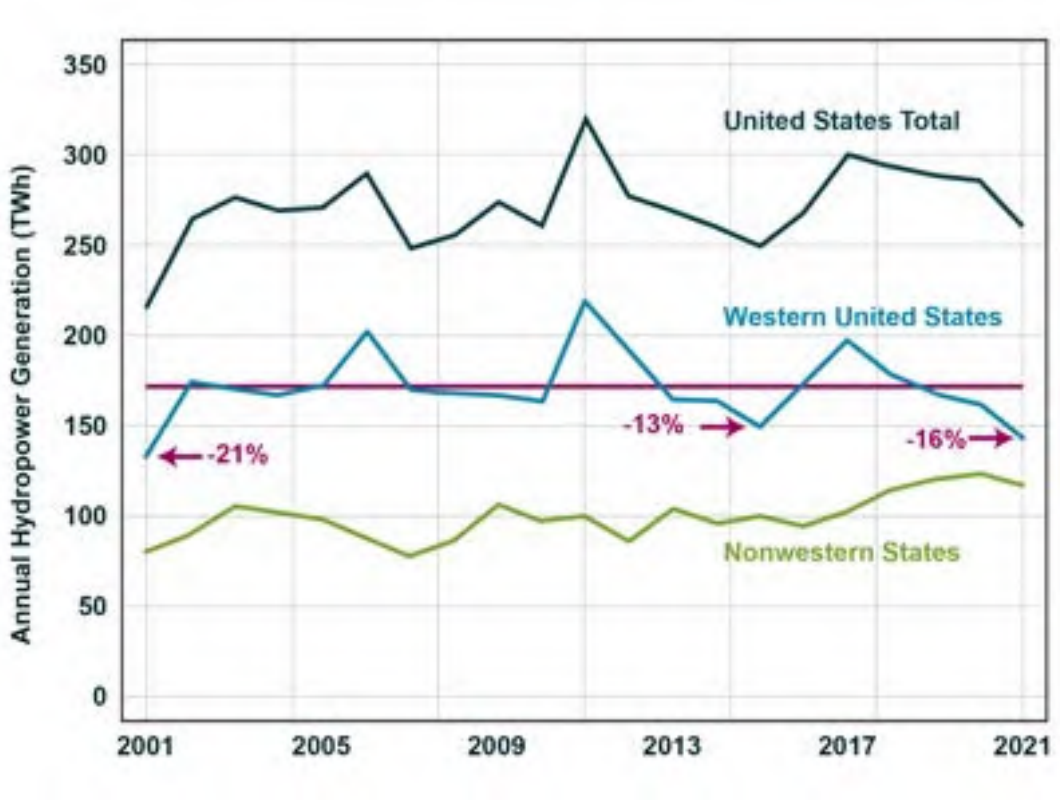


Figure 5. Total hydroelectric power generation in the United States, western U.S. states, and nonwestern states

*Western states are defined as Washington, Oregon, California, Idaho, Montana, Utah, Colorado, Nevada, Arizona, Wyoming, and New Mexico. Percentages give the deviation from the mean annual western U.S. generation (solid magenta line). (Data source: Energy Information Administration (EIA) state-level generation reports; Turner et al., 2022)*

The study team made a deliberate decision to focus on heatwave events (2015 and 2018) that did not coincide temporally with the drought conditions of 2001. This decision allowed the study team to simulate drought conditions that could induce significant stress on the grid. By using the 2001 hydrologic data, the study team created a multievent threat representing a co-occurrence of significantly reduced hydropower generation capacity alongside the increased energy demand. This allowed the study team to test the NTP Study transmission scenarios under compounded extreme conditions.

## 2.2 Modeling Inputs for Extreme Stress Events

### 2.2.1 Hourly load

After selecting the extreme events, the study team simulated how the hourly load evolved during the events. The tool for simulating load is the extensively documented, open-source, Total ELectricity Loads (TELL) model (McGrath et al. 2022). TELL ingests hourly time-series meteorology data at the balancing authority (BA) level[9] and then uses machine learning (ML) to simulate the hourly evolution of total electricity demand within

[9] For more information about the BA's geographical boundaries, see Appendix B.

the BA in response to weather variations. TELL is a nationwide model that works for all BAs in the contiguous United States. Using the weather projections and then scaling to the annual energy values in the 2035 base year loads (Figure 6), the study team used TELL to generate 8,760-hour load profiles for each BA based on the 2015 and 2018 weather years with climate change. Appendix A provides the details of this approach.

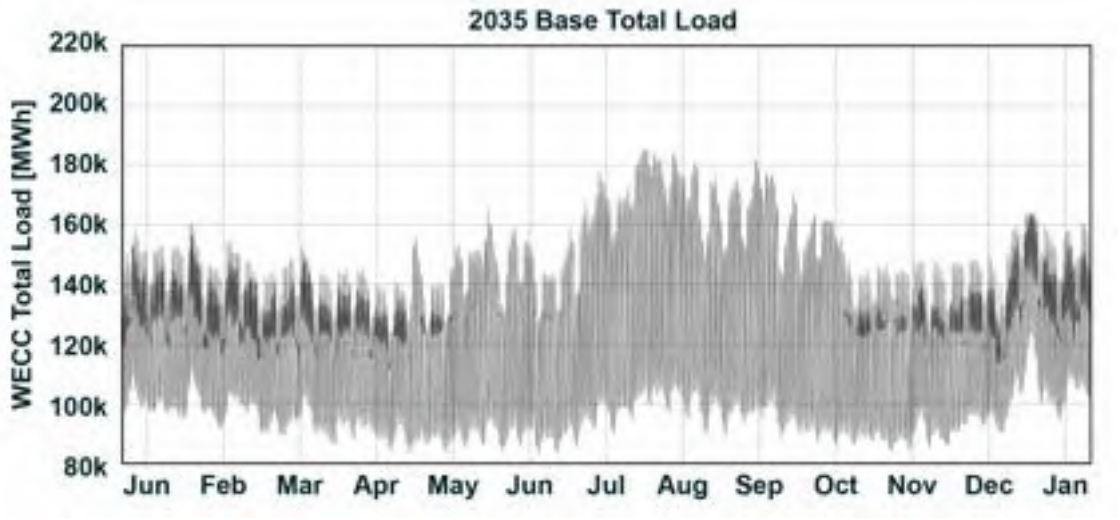


Figure 6. Hourly loads in 2035 in the Western Interconnection for the NTP base year. This load time series is based on the 2009 weather year.

*WECC = Western Electricity Coordinating Council; MWh = megawatt-hour*

Figure 7 displays the 2035 scaled loads provided by TELL based on the 2015 weather year. The 2015 NTP Study heatwave event is highlighted using blue shading. The total peak load in the Western Interconnection exceeds 210,500 megawatts (MW) during the heatwave period. For reference, the maximum total load in the Western Interconnection is ~185,500 MW in the base 2035 NTP Study loads.

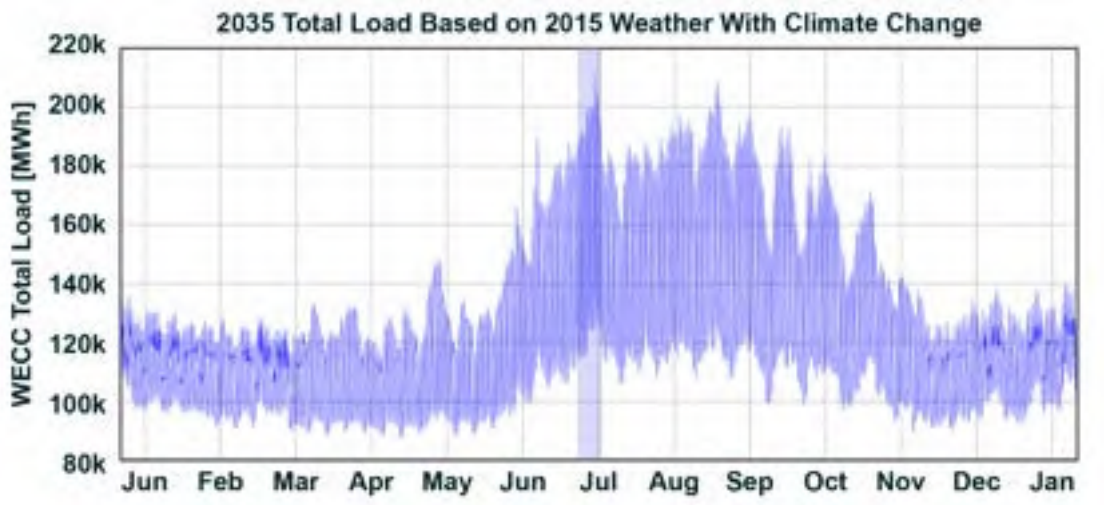


Figure 7. Hourly loads in 2035 in the Western Interconnection based on the 2015 weather year with climate change

*The shaded blue box highlights the 2015 NTP heatwave event.*

Figure 8 shows the 2035 scaled loads that TELL provided based on the 2018 weather year. The 2018 NTP heatwave event is highlighted using red shading. The total peak load for the Western Interconnection exceeds 217,900 MW during the heatwave period.

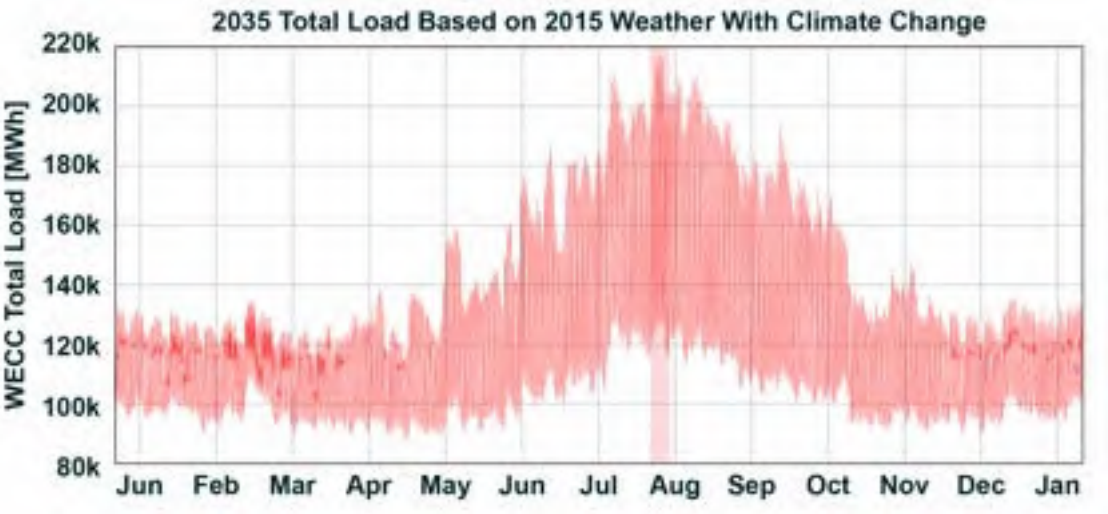


Figure 8. Hourly loads in 2035 in the Western Interconnection based on the 2018 weather year with climate change

*The shaded red box highlights the 2018 NTP Study heatwave event.*

### 2.2.2 Hourly solar and wind profiles

The study team developed hourly wind and solar profiles for specific locations associated with solar plants using a gridded generation dataset (Bracken, Thurber, and Voisin 2023) (Figure 9). The study team developed coincident renewable generation profiles for the 2015 heatwave in the PNW and the 2018 heatwave event in California and the Desert Southwest, including profiles reflecting warming consistent with

Representative Concentration Pathway (RCP) 8.5, which were input into GridView. For more details about the process of generating hourly wind and solar profiles, see Appendix B.

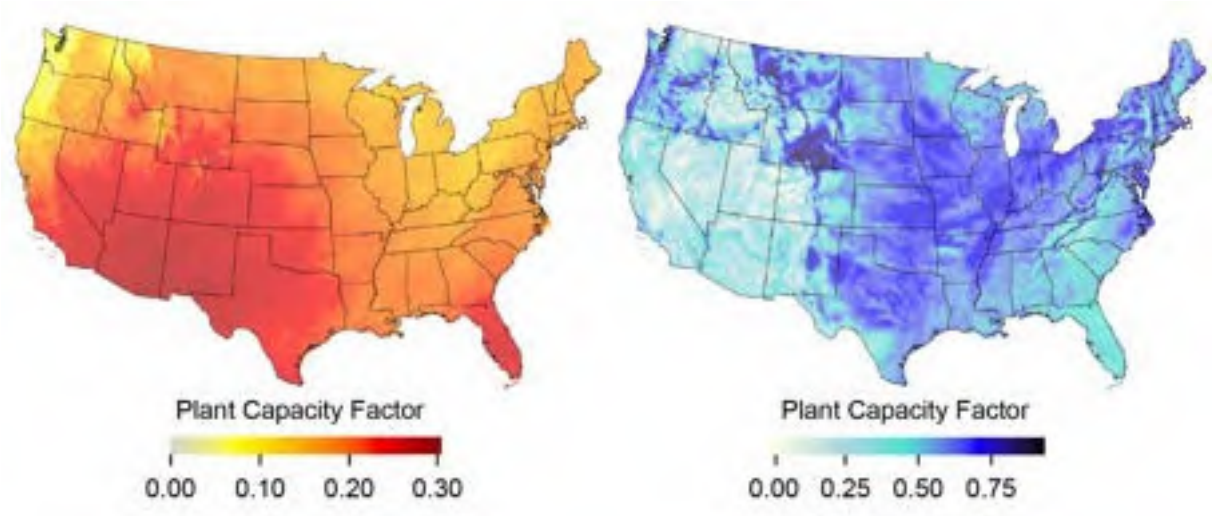


Figure 9. Example of gridded solar (left) and wind (right) generation data

*The gridded wind and solar data assume a hypothetical plant located at every grid cell and are derived from downscaled meteorology data (Jones et al. 2023).*

### 2.2.3 Hydropower availability

GridView requires hydropower data in the form of weekly energy targets and constraints that reflect the physical limitations of each hydropower facility. The team used an existing weekly hydropower constraint dataset for 1,500 hydropower plants (Turner et al. 2024). This dataset contains monthly power generation estimates for 1,500 hydropower plants that are disaggregated from annual EIA-923 power generation data using observed streamflow and power production data. The dataset derives hydropower constraints (minimum operating capacity, maximum operating capacity, energy targets, and so on) from disaggregated data based on historical operating ranges and power generation. These data are designed for use in GridView. Figure 10 shows the modeling framework used to produce the weekly hydropower dataset.

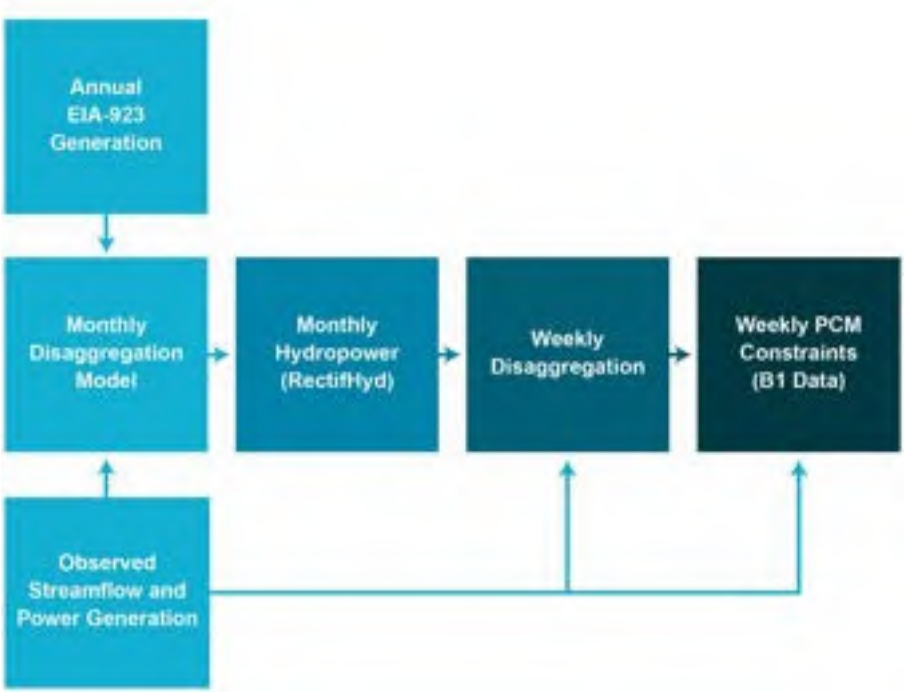


Figure 10. Modeling framework for generating weekly hydropower datasets

*PCM = production cost model*

The study team used the 2001 hydrologic year, which was historically dry, to represent low hydropower conditions. The study team imported the 2001 water availability—expressed in weekly energy budgets (MWh)—and the weekly operating maximum and minimum MW values into GridView at the individual plant level. The study team then adjusted the hydropower parameters for 1,200 hydropower plants to reflect the 2001 hydrology. Figure 11 shows a representation of the total WECC weekly energy targets for 2001 and 2009 (an average year). The weekly values in 2001 range from 13% above the generation in 2009 to 42% below the generation in 2009, depending on the week. The total generation in 2001 is 17.6% below the generation in 2009. The study team did not include Canadian hydropower plants in this drought parameterization because of the absence of sufficient hydropower data needed to establish monthly energy targets and operating ranges.

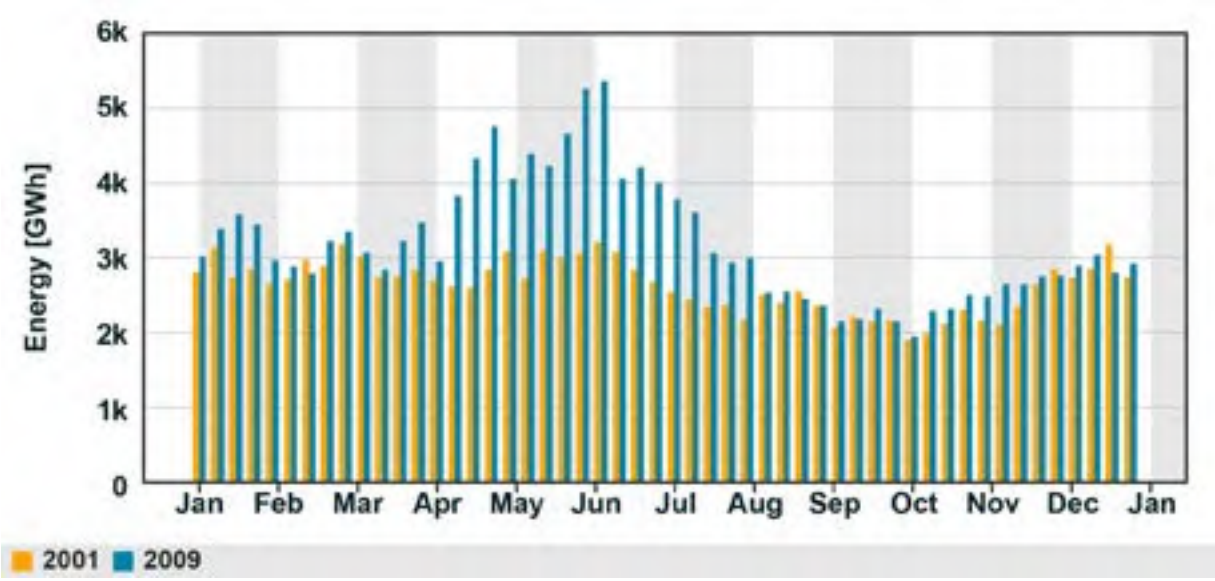


Figure 11. Total WECC weekly energy targets for the drought year under study (2001) and a year with average hydrologic conditions (2009)

GridView dispatches most hydropower plants based on hydrothermal coordination (HTC) logic. Within the HTC logic, GridView conducts hydropower scheduling in response to the net demand (load, wind, solar) of its designated load area. HTC requires the GridView optimizer to be initially run with a hydropower schedule to obtain 24-hour price signals, adjusting this schedule based on these price signals, and then rerunning the unit commitment and economic dispatch with the updated hydropower schedule.

## 2.3 Methodology for the Economic Analysis Under Extreme Stress Conditions

The study team estimated the economic benefits between the Lim and AC transmission scenarios for the stress events under study. The first type of benefit estimated is the avoided costs of generation; the second type is the reduction in the cumulative value of lost load (C-VOLL) calculated by multiplying the quantity of unserved load by the value of lost load (VOLL). Note the realized economic benefits during extreme stress events cannot be added directly to the economic benefits reported in Chapter 3 without considering the probability of the event occurring, which is beyond the scope of this chapter.

The avoided cost of generation is the difference in generation costs between the Lim and AC scenarios. Extreme events could reduce the generation from hydro, wind, and solar. Other generation types such as fossil fuels replace this lost generation, which incurs additional operating costs. The study team estimated the operating costs using the outputs from the GridView simulations and included changes in fuel costs, startup costs, and variable operations and maintenance (O&M) costs. The extreme event analysis used the same transmission expansion topology as the one in the standard Lim and AC scenarios. Therefore, the generation capital costs—and the transmission capital

costs used in this chapter—are identical to those provided in Chapter 3. Thus, the benefits of avoided capital costs are zero for the extreme event economic analysis to avoid double-counting.

The second estimated benefit is the difference in the C-VOLL for the AC topology and the C-VOLL for the Lim topology. The C-VOLL is the quantity of unserved load for each stress event–transmission scenario combination multiplied by the VOLL. The VOLL is a measure of the monetized value lost to residential and nonresidential electricity consumers during a power outage, usually in $/kilowatt-hour (kWh) (Gorman 2022). The VOLL for residential customers evaluates the cost of electricity outages based on survey data collected from residential customers (Baik et al. 2018). Economic loss surveys explore losses from electricity outages across several dimensions, such as lost wages, added travel costs, lodging because of dislocation, dining out, replacing spoiled food, and/or operating a backup generator because of electricity outages. The losses to nonresidential end users include the loss of productivity, the loss of revenues, and the loss of equipment and its cost to replace (Amadi and Okafor 2015). Survey respondents are asked to estimate their losses because of an electricity outage by the duration of an outage. However, the values do not capture indirect losses, supply chain issues associated with outages greater than 24 hours, or the long-duration lost load (Rose et al. 2005). Measuring the value of the long-duration lost load is still in development by other research organizations (Larsen et al. 2019).

The VOLL is not necessarily constant. It can vary by customer type (residential, commercial, and so on), location, time of day, and outage duration (Sullivan et al. 2015). For outages with unserved energy *Q* across location *l*, time of day *t*, and duration *d* and affecting customer type *c*, the study team computed the total C-VOLL using the following equation:

$$C\text{-}VOLL = \sum_{l,t,d,c=0}^{L,T,D,C} Q_{ltdc} \times VOLL_{ltdc}$$

The study team obtained unserved load quantity estimates from the production cost model for each transmission scenario (i.e., Lim and AC) and stress event combination for the Lim and AC frameworks. The study team obtained VOLL estimates from the Interruption Cost Estimate (ICE) calculator (Berkeley Laboratory n.d.). The ICE calculator obtained these VOLL estimates for each load area based on the proportion of the load area within each state. The ICE calculator provides the following VOLL estimates for the Western Interconnection: residential, $5/kWh; small commercial and industrial, $200/kWh; and large commercial and industrial, $90/kWh. The average VOLL is $80/kWh.

As previously mentioned, the realized economic benefits of reliability during extreme stress events cannot be added directly to the economic benefits reported in Chapter 3. To add the reliability benefits to other types of economic benefits (e.g., operating cost and capital cost), the expected value in reliability benefits should be used to estimate an

annualized value or net present value[10] of the suitability of different transmission projects. The expected value is calculated by multiplying the realized reliability benefits when the event occurs by the probability of the event occurring. Ideally, the expected value should be computed across a range of extreme events (often called an *all-hazards analysis*) and summed with estimates of other benefit types to obtain the total benefits that can then be used for a cost-benefit analysis (Macmillan et al. 2023). Estimating event probabilities is outside the scope of this study, so the study team did not combine the benefits in this chapter with the general operating benefits presented in Chapter 3. As such, the reader should be cautioned not to add the benefits presented here to other benefit types or directly compare their magnitude to other benefit types.

[10] The net present value provides the discounted benefits of each stress event and transmission scenario combination, including the difference in the transmission and generation capital costs associated with implementing the different generation and transmission scenarios. A positive value would indicate the AC scenario provides a better option than the Limited scenario. Although this chapter does not include net present value calculations, the methodology for computing net present value and the selection of discount rates are discussed in Chapter 3.

# 3 Description of Transmission Expansion Scenarios

Before presenting the results of the extreme stress cases, this section briefly outlines the two nodal transmission scenarios. It provides context for the transmission and generation included in these scenarios, upon which the stress cases were applied.

As described in Chapter 3, the NTP Study used the WECC 2030 Anchor Dataset (ADS) PCM dataset as the starting nodal PCM case for the Western Interconnection. ADS (WECC 2020a, 2020b) is the most reliable forecast for upcoming developments in new generation, generation retirements, transmission assets, and load growth, providing 10-year predictions from specified reference years.

The NTP Study added transmission projects to the 2030 ADS that are either under construction or have significantly progressed through the permitting process and thus are deemed both plausible and likely to materialize. The study team identified additional transmission projects for the year 2035 in the capacity expansion model, which optimizes for the lowest-cost mix of transmission and generation to meet a set of input assumptions and constraints—which is designed to predict future infrastructure and transmission needs (Chapter 2). The study team used a zonal-to-nodal approach (Chapter 3) to build two distinct production cost models for year 2035: the 1) Alternating Current (AC) and 2) Limited (Lim) scenarios. These two scenarios are based on the same high demand estimate[11] and aim to achieve 90% decarbonization by the year 2035, albeit through divergent transmission and generation capacity expansion strategies. The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., Federal Energy Regulatory Commission [FERC] Order No. 1000), whereas the 2035 AC Lim scenario permits transmission buildouts solely within these planning regions. For the Western Interconnection, the FERC No. 1000 regions consist of California Independent System Operator (CAISO), WestConnect, and NorthernGrid; Figure 14 displays the borders of these regions.

Figure 12 and Figure 13 show an overview of the two nodal transmission expansion scenarios.

[11] This represents an increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, see Chapter 2, earlier (Round 1) ReEDS scenario.

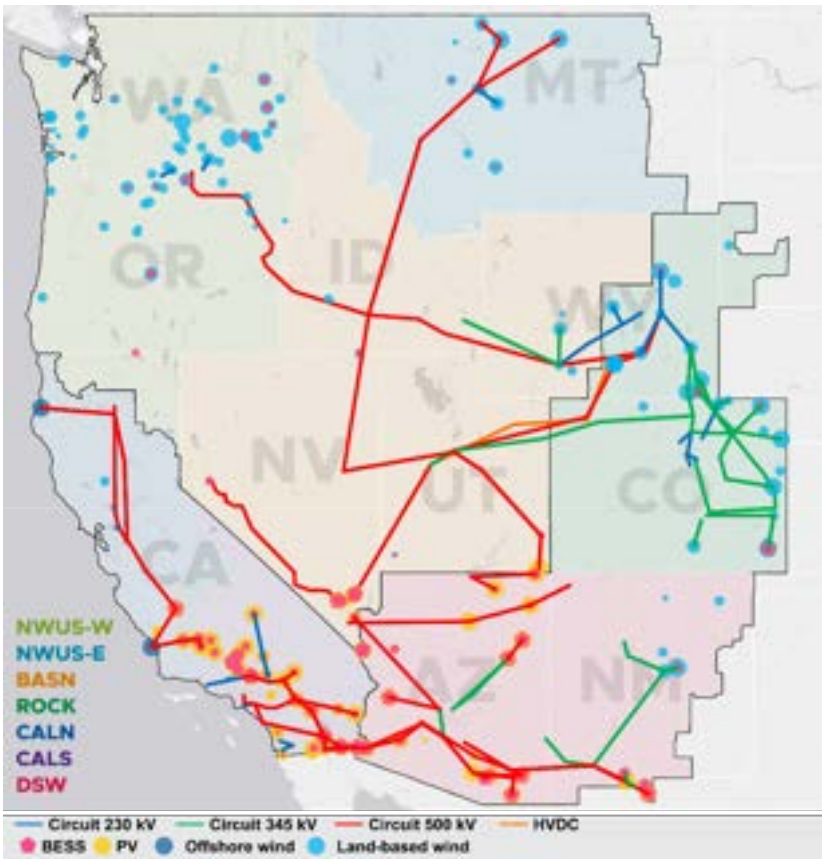


Figure 12. Transmission expansion in the 2035 Lim scenario from the 2030 ADS: 500-, 230-, and 345-kilovolt (kV) circuits are added or updated; new HVDC circuits are added

*BESS = battery energy storage systems; PV = photovoltaic*

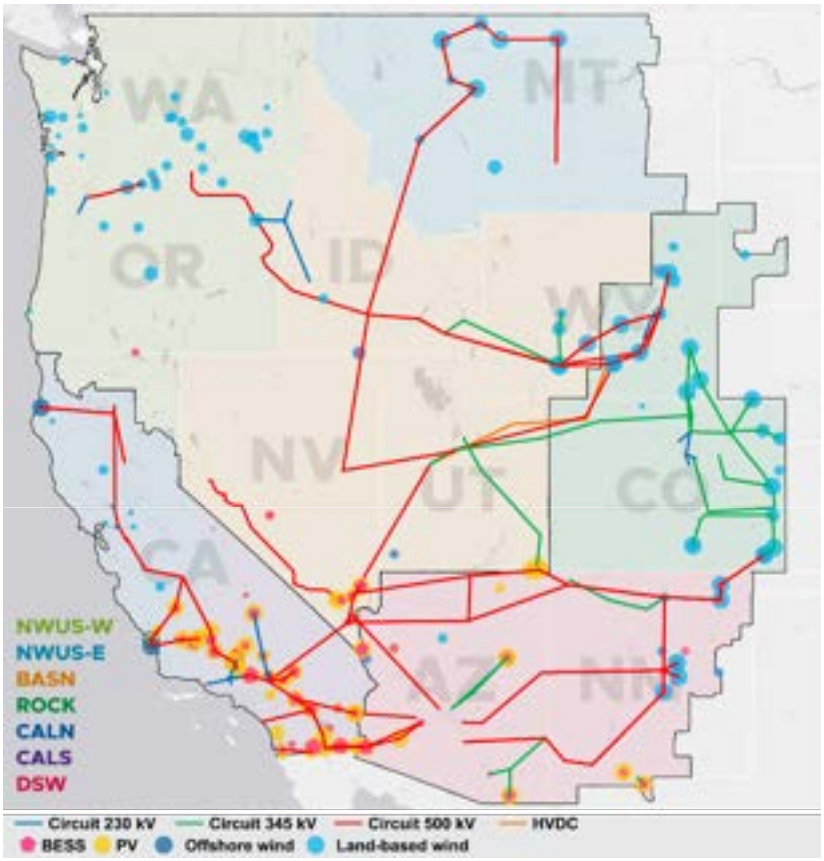


Figure 13. Transmission expansion in the 2035 AC scenario from the 2030 ADS: 500-, 230-, and 345-kV circuits are added or updated; new HVDC circuits are added

Figure 14. Three FERC Order No.1000 regions: CAISO, NorthernGrid, WestConnect; six WECC regions (excluding Alberta, British Columbia, and Northern Baja California Mexico): Basin (BASN), California North (CALN), California South (CALS), Desert Southwest (DSW), Northwest United States (NWUS), and Rocky Mountain (ROCK)

Figure 15 shows the total installed capacity mix for the two transmission expansion scenarios at both a WECC level (a) and WECC regional level (b), as depicted in Figure 14. Figure 15 also shows the capacity difference between the two scenarios (Lim minus AC capacity) at a WECC level (c) and WECC regional level (d). Solar, wind, and BESS emerge as the primary capacity resources. Solar and battery storage capacity predominantly reside in the California South and Desert Southwest regions for both the Lim and AC scenarios whereas wind capacity is primarily situated in the Northwest and Rocky Mountain regions. The AC scenario exhibits more installed wind capacity, particularly in the Rockies and Basin regions, compared to the Lim scenario, which records higher solar and BESS installed capacity—notably in the Desert Southwest and California South regions.

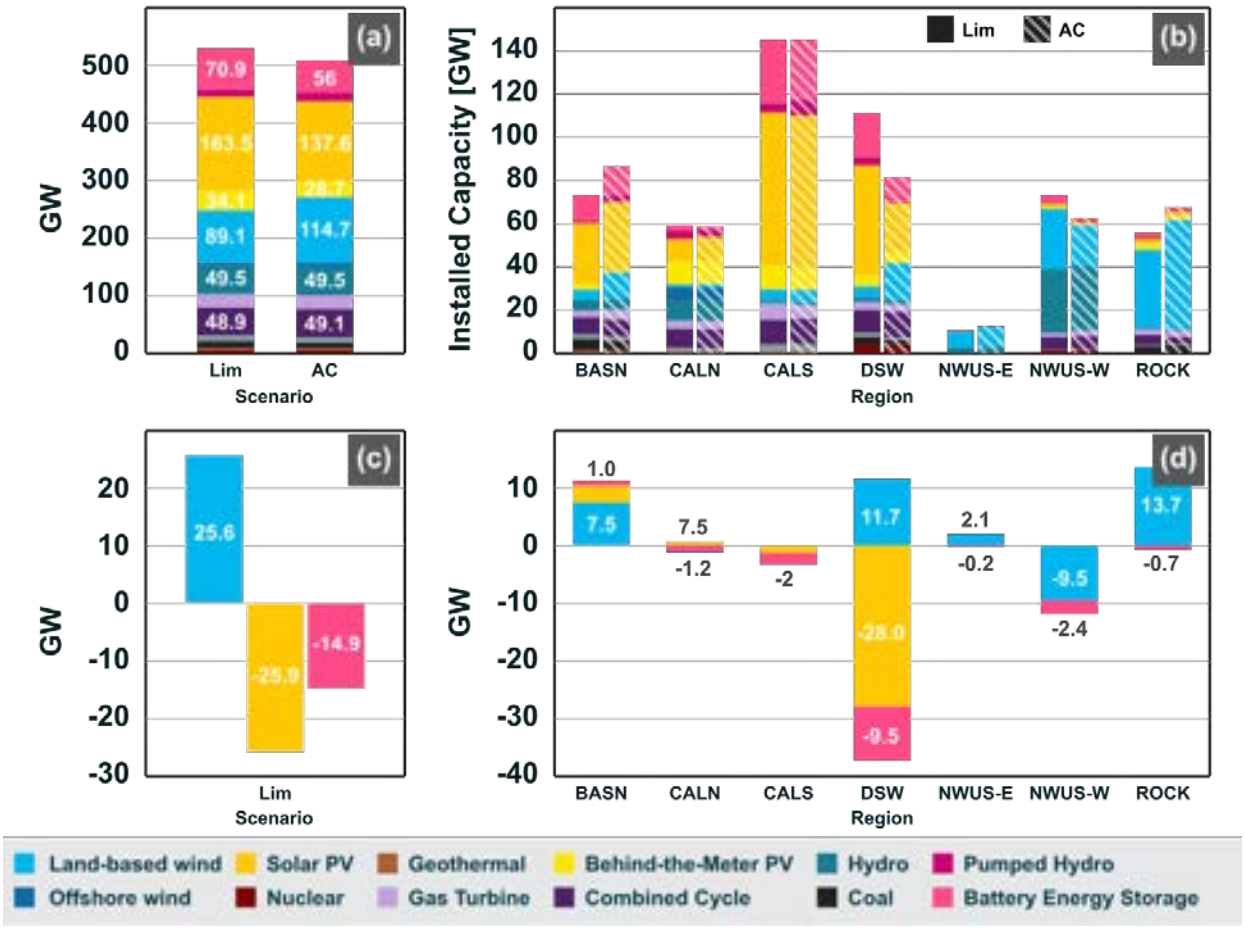


Figure 15. Total installed capacity of the 2035 AC and 2035 Lim scenarios at a WECC level (a) and WECC regional level (b) and their capacity difference (Lim minus AC capacity) at a WECC level (c) and WECC regional level (d)

# 4 Stress Case Results and Key Findings

The study team defined four stress cases based on historical events in the West and used production cost simulations for both nodal transmission scenarios to generate 8 simulation results (4 stress cases × 2 scenarios; Table 1). As previously stated, this chapter uses the acronyms "AC" and "Lim" to refer to the Alternating Current and Limited transmission scenarios, and "H" and "H+D" to represent the heatwave and combined heatwave and drought events. To simplify the discussion, this chapter refers to these occurrences as the PNW heatwave, representing the 2015 heatwave event, and California (CA) heatwave, representing the 2018 heatwave event, in the following text.

Table 1. Stress Case Scenarios

| Stress Case | Stress Event |
|---|---|
| 1 | California heatwave |
| 2 | California Heatwave + Pacific Northwest drought |
| 3 | Pacific Northwest heatwave |
| 4 | Pacific Northwest heatwave + Pacific Northwest drought |

To evaluate the reliability, economic, and operational impacts of stress cases on the two transmission scenarios, the study team conducted production cost simulations for an entire year for each of the eight stress cases. Unserved energy[12] is the key metric used to quantify the impact of extreme events on grid operations, measured both in energy values (GWh) and as a percentage of total load. In addition, the study team examined the loading of key interface path and transmission lines. The term "key" refers to interface paths where either the starting or receiving endpoints are situated in areas susceptible to extreme stress events. An interface path may comprise multiple transmission lines connecting different areas.

Following are the two main differences between the two transmission scenarios:

- The AC scenario facilitates expansion between transmission planning regions (FERC Order No. 1000). As shown in Figure 13, most of these interregional AC lines serve to connect WestConnect (i.e., Desert Southwest and Rockies) with California, effectively channeling the rich wind energy from New Mexico and Colorado to meet California's substantial demand.
- The Limited scenario features roughly 7.5 GW more installed capacity in California than the AC scenario (Figure 16). This substantial margin is crucial for the forthcoming analysis, especially given half of this capacity is derived from dispatchable sources such as energy storage (ES) and natural gas (NG).[13]

[12] Many factors can cause unserved loads, including capacity shortage, ramping capability shortage, bad commitment decisions (units cannot participate in generation during the minimum downtime), forced generator outages, and transmission limitations.
[13] It is important to note because the capacity mix of each scenario is different, the conclusions on transmission benefits between the two scenarios are not being identified in isolation.

The results are provided at a regional level for PNW and California.

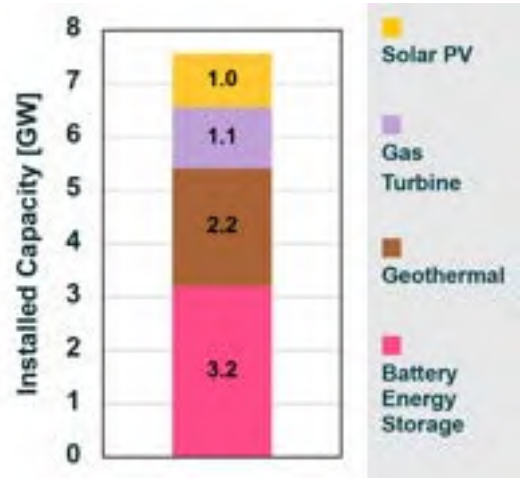


Figure 16. Capacity difference between the Lim and AC scenarios for California

*The Lim scenario has roughly 7.5 GW more installed capacity in California than the AC scenario.*

## 4.1 Compounded Extreme Events Lead to Higher Levels of Unserved Energy Than Individual Events

Figure 17 shows the single heatwave event in California leads to unserved energy in both California and PNW, especially under the Lim scenario (1.5% and 1.3% of the total load in California and PNW, respectively), which does not facilitate expansion between transmission planning regions. When the California heatwave is combined with hydro droughts in PNW, the unserved energy increases for both regions and across transmission scenarios. Specifically, in the Lim scenario, unserved energy rises to 3.8% and 7.7% for California and PNW, respectively, during the California heatwave and PNW drought.

Similarly, when the PNW heatwave is coupled with the PNW drought (Figure 18), the unserved energy ranges between 1.5% and 6.2%, depending on the transmission scenario and heatwave region, unlike during heatwave-only scenarios where unserved energy remains below 1%. This finding underscores the profound impact drought conditions have on the reliability of the Western Interconnection, especially in hydropower-dependent areas such as PNW.

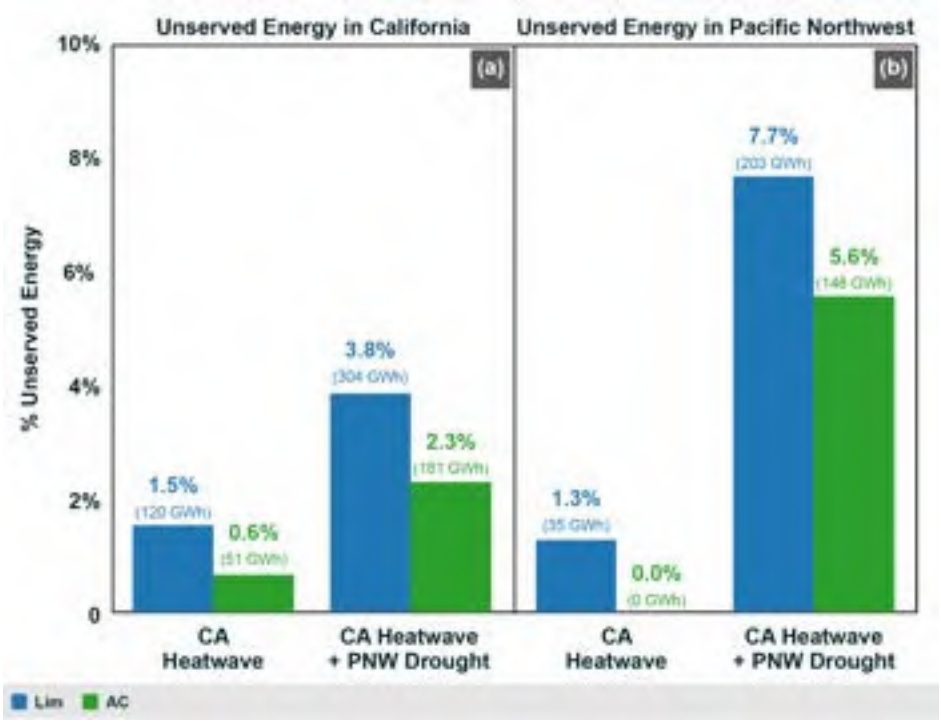


Figure 17. Percent of unserved energy in California (a) and PNW (b) during the California heatwave (July 22–July 28) and combined California heatwave and PNW drought

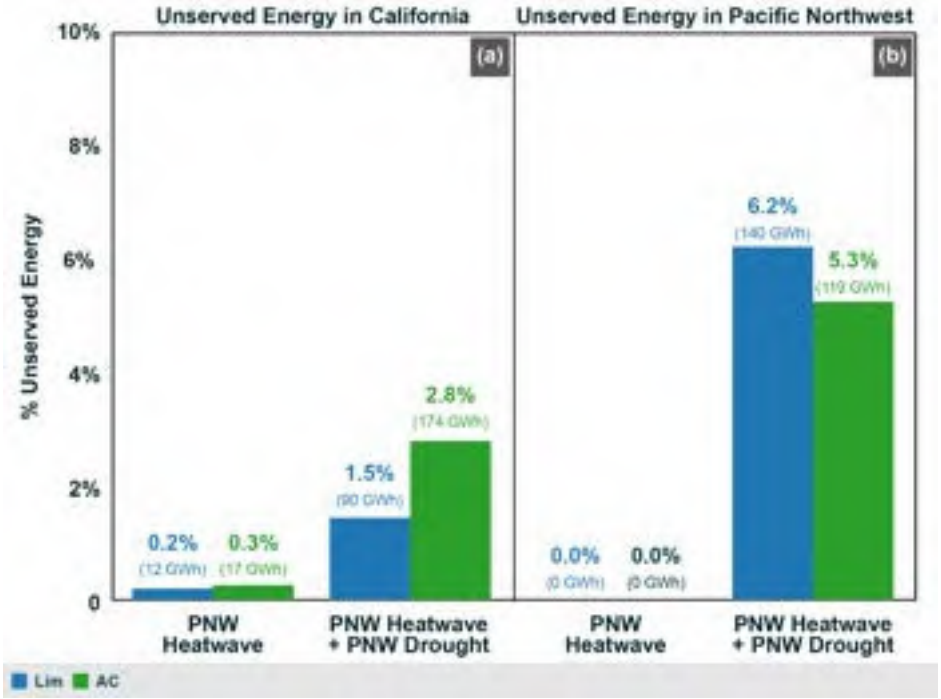


Figure 18. Percent of unserved energy in California (a) and PNW (b) during the PNW heatwave (June 25–July 2) and combined PNW heatwave and PNW drought

The impact of drought is predominantly evident in PNW, with a significant reduction in hydro generation compared to the single-heatwave event across both transmission scenarios and heatwave events, as shown in Figure 19 and Figure 20. There is approximately a 20% reduction during the June PNW heatwave event and a 17% reduction during the July California heatwave event for both transmission scenarios. To compensate for the supply shortfall, both the California and PNW and transmission scenarios (Figure 19 and Figure 20) show increased reliance on NG resources (gas turbines and combustion cycle).

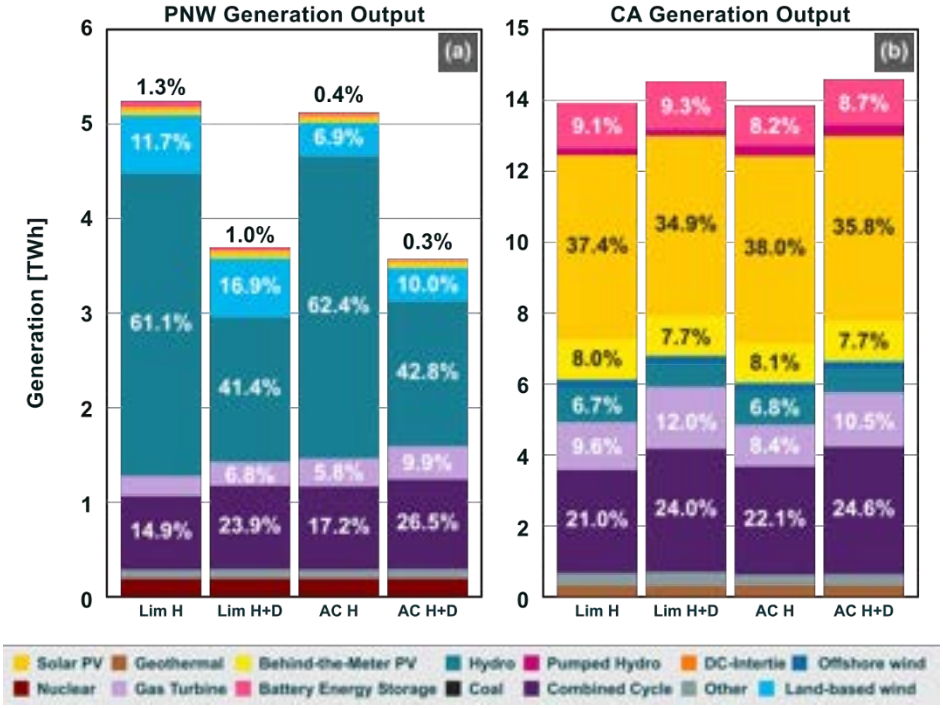


Figure 19. Generation output of PNW (a) and California (b) for the two transmission scenarios (AC and Lim) under stress conditions during the PNW heatwave (H) and combined PNW heatwave and PNW drought (H+D)

*TWh = terawatt-hour*

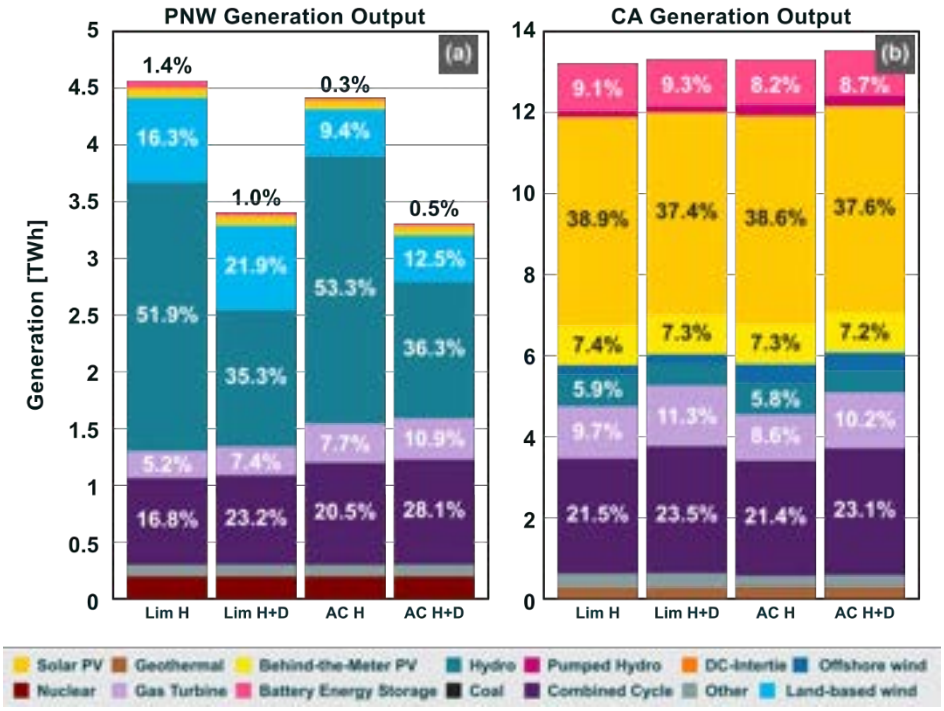


Figure 20. Generation output of PNW (a) and CA (b) for the two transmission scenarios (AC and Lim) during the California heatwave and combined California heatwave and PNW drought (H+D)

## 4.2 Unserved Energy Peaks in the Morning Because of Low Online Energy Resource Availability and Increasing Load Ramps

The timing of unserved energy is a critical aspect to consider. Figure 21a displays the hourly distribution of unserved energy in California of the two transmission scenarios over a 3-day period (July 22–24) during the combined California heatwave event and PNW drought. Notably, unserved energy peaks during the early morning hours, prior to solar generation coming online, aligning with the morning load ramp and when energy storage—including both systems (BESS and pumped hydro storage [PHS])—is nearly exhausted (Figure 21b, c). The amount of unserved energy is intensified in the Limited scenario, represented by the light blue line in Figure 21a. This outcome underscores the critical importance of interregional capacity in boosting California imports during these early morning hours, significantly reducing unserved energy—although not eliminating it. The scenario where the PNW heatwave is combined with the PNW drought exhibits the same timing of unserved energy.

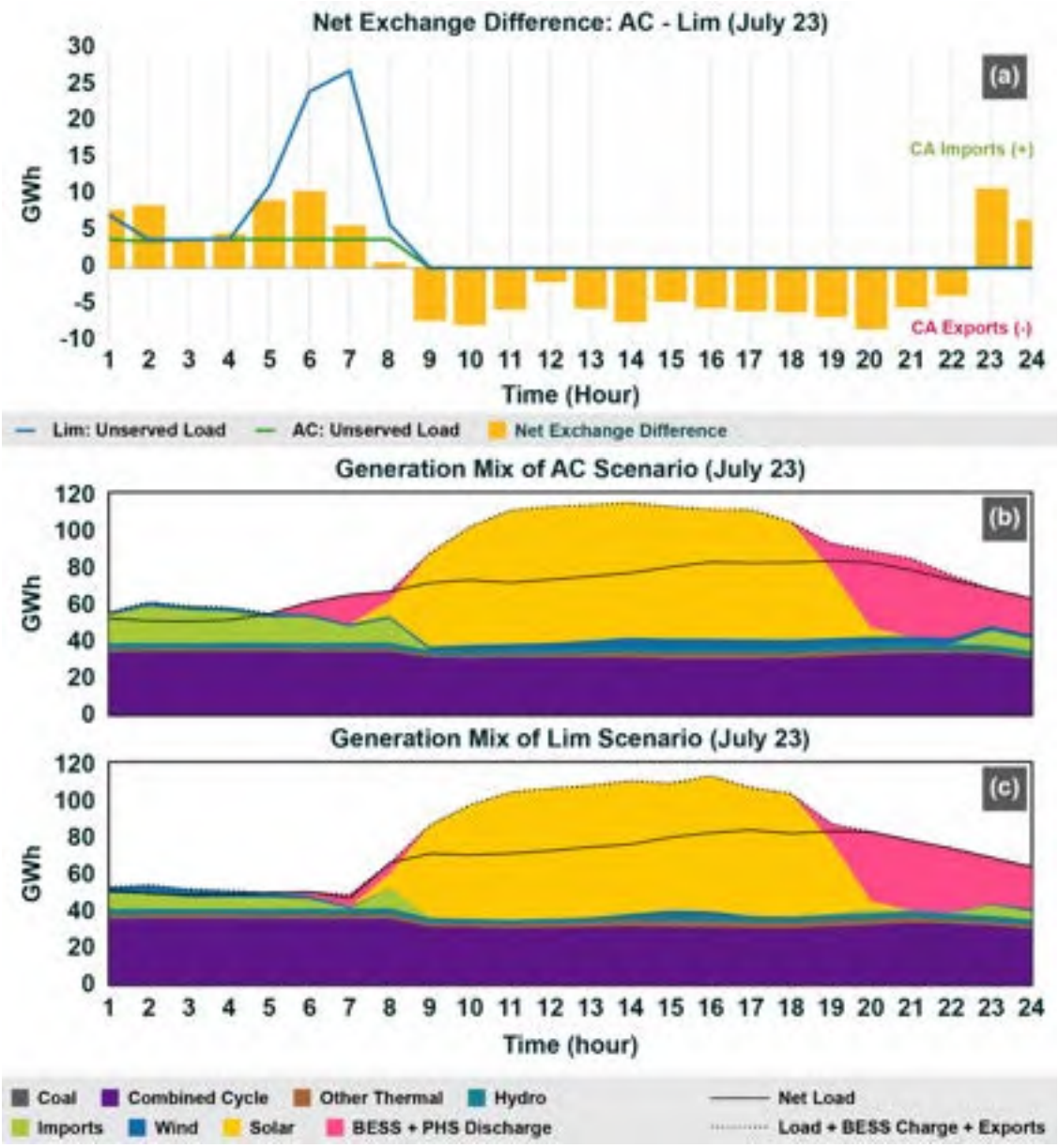


Figure 21. Hourly unserved energy (a) and generation mix (b, c) of the two transmission scenarios during the combined California heatwave (July 23) and PNW drought

*In (a), the orange bars show the hourly net exchange difference between the AC and Lim scenarios, highlighting the interregional support to California (+) during those morning hours.*

## 4.3 Interregional Transmission Capacity May Offer Significant Advantages to Regions Affected by Extreme Events by Diversifying Their Energy Resource Mix

During the combined California heatwave and PNW drought, the study team observed the Lim scenario exhibits higher amounts of unserved energy: 7.7% in PNW (Figure 17b) and 3.8% in California (Figure 17a). This is in contrast to the AC scenario, which shows lower levels of unserved energy: 5.6% in PNW (Figure 17b) and 2.3% in California (Figure 17a). This result clearly shows the benefits of the interregional transmission capacity of the AC scenario, which supports serving more energy than the limited within-region topology.

More specifically, the interregional transmission capacity can benefit regions of the system that are experiencing extreme events by diversifying their generation mix both technologically and geographically. This is shown in Figure 22, which demonstrates how wind resources from regions abundant in wind energy, such as New Mexico and Colorado, meet California's heatwave demand through new interregional transmission corridors.

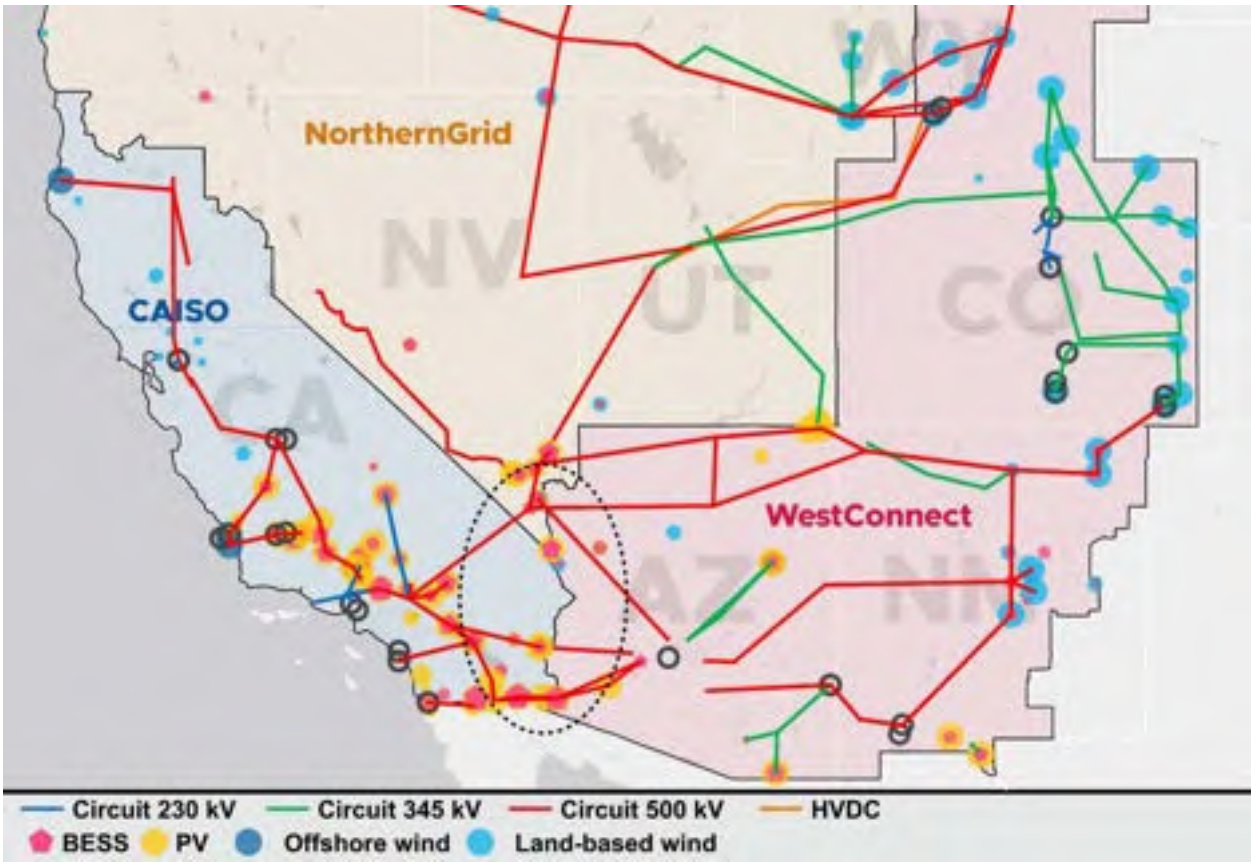


Figure 22. New Interregional AC connections crossing FERC Order No. 1000 borders

*The black dotted circle encapsulates the new AC interregional lines crossing WestConnect, CAISO, and NorthernGrid.*

Two newly added interregional transmission corridors, which were instrumental in supporting California during the combined California heatwave and PNW drought, connect southern Nevada to southern California via two parallel 500-kV lines and Arizona to the Imperial Valley Area (California), also via two parallel 500-kV lines (Figure 23).

These lines substantially help transfer electricity in southern California during the combined California heatwave and PNW drought. As shown in Figure 24, during the heatwave, California experienced a substantial surge in electricity imports, particularly in the morning hours. This surge is in response to the morning load ramp compounded by the absence of solar generation and depleted energy storage resources (BESS and PHS). Subsequently, the import levels consistently remain above zero for the rest of the day, indicating a sustained need for power.

Figure 24 also illustrates a preheatwave day (July 11) to show the difference in power flows during the California heatwave event (July 23) and slightly before the heatwave (July 11). During the preheatwave day, there is an export of power to the Desert Southwest region at midday, indicating a surplus of solar generation in California.

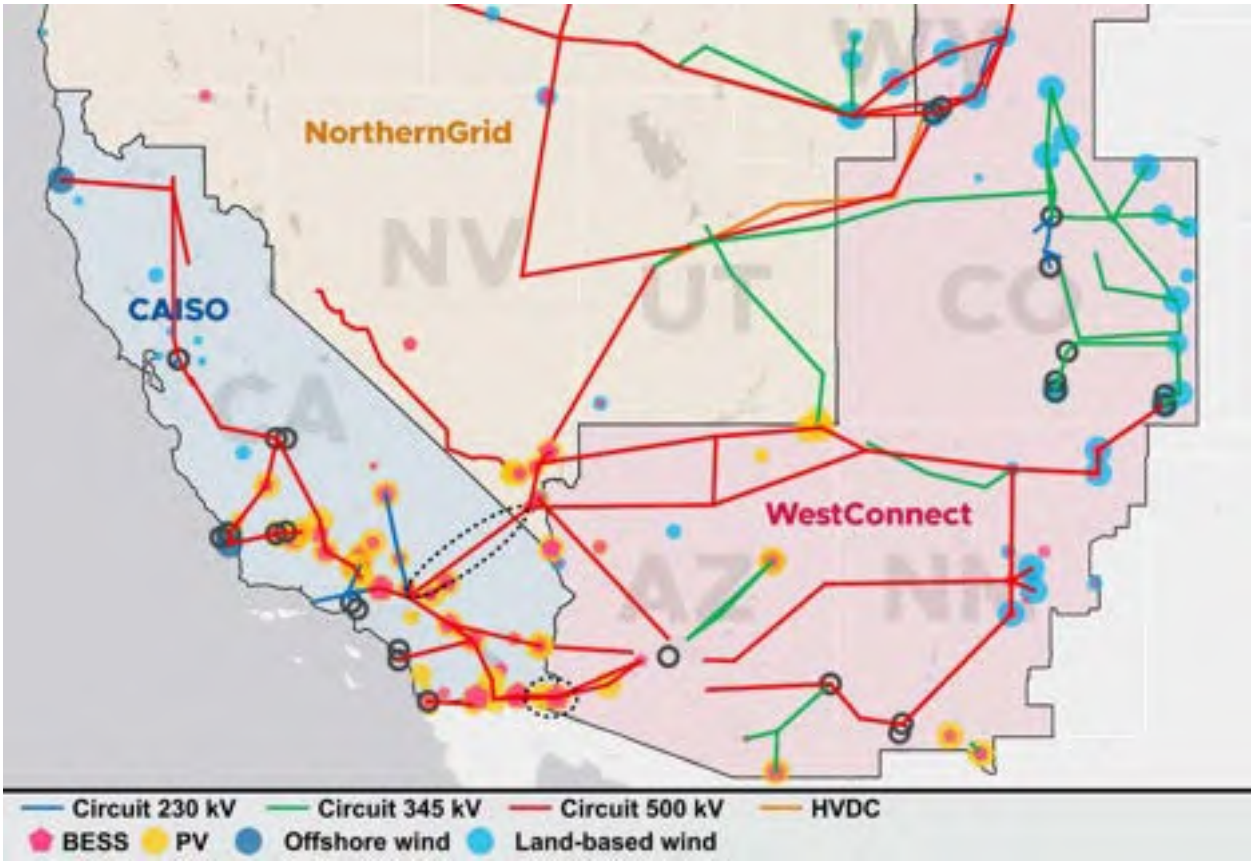


Figure 23. Example of new AC corridors connecting southern Nevada to southern California (indicated by the top black dotted circle) and Arizona to the Imperial Valley Area in California (indicated by the bottom black dotted circle)

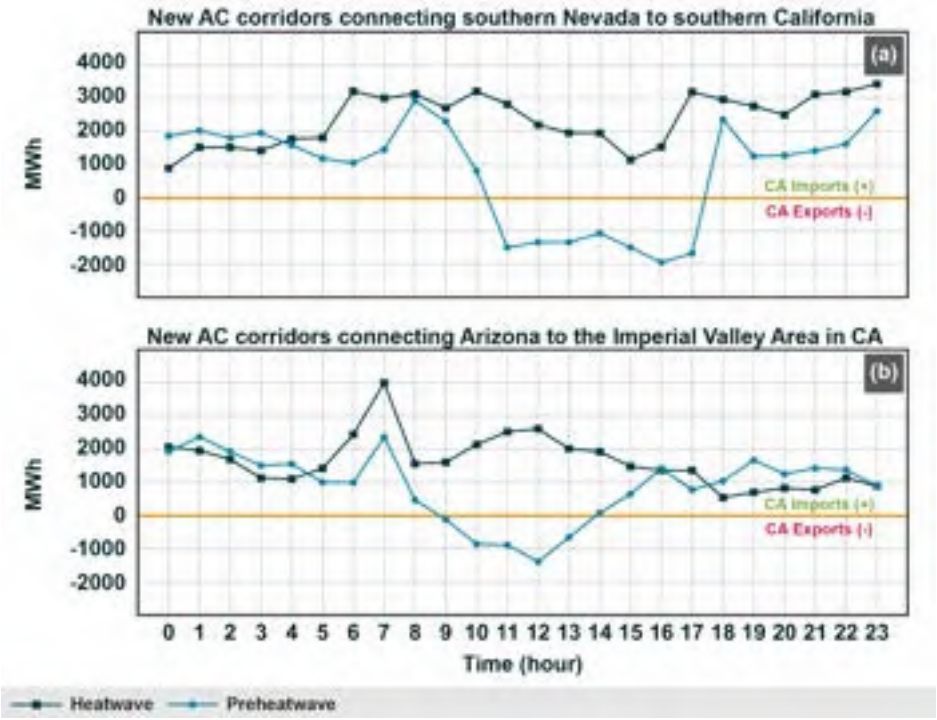


Figure 24. Hourly power flows during heatwave and preheatwave days for the corridors connecting southern Nevada to southern California (a) and Arizona to the Imperial Valley Area in California (b)

The study team observed similar behavior in key interface paths where either the starting or receiving endpoints are in regions affected by extreme stress events, such as PNW and California. These interface paths, numbered 46, 65, 66, 14, and 8 according to WECC, connect the two regions (PNW and California) either themselves or with the rest of the Western Interconnection. For more information about the WECC interface path, see Appendix D.

Starting with Path 46 (West of the Colorado River), which links Desert Southwest (specifically southern Nevada and Arizona) with Southern California, there is a noticeable increase in imports to California during the heatwave day—particularly in the morning hours to mitigate unserved energy (Figure 25).

Transitioning onto Paths 65 (Pacific DC Intertie) and 66 (California Oregon Intertie), which link PNW with Southern and Northern California, respectively, Figure 26 shows an increase in imports to California during the morning and evening hours to support the state during morning and evening load ramps whereas California's exports rise during solar peak hours.

Path 14, which links Idaho and PNW and contains the Boardman to Hemingway (B2H) segment (Figure 27), facilitates an increased flow of power to PNW throughout the day—particularly in the morning hours—and Paths 65 and 66 subsequently channel a portion of this energy to California.

Finally, Path 8 (Figure 28), connecting Montana to PNW, shows increased imports to PNW from Montana during the morning periods of the California heatwave. This bolsters PNW's capacity to cope with the compounded stress of heat and drought.

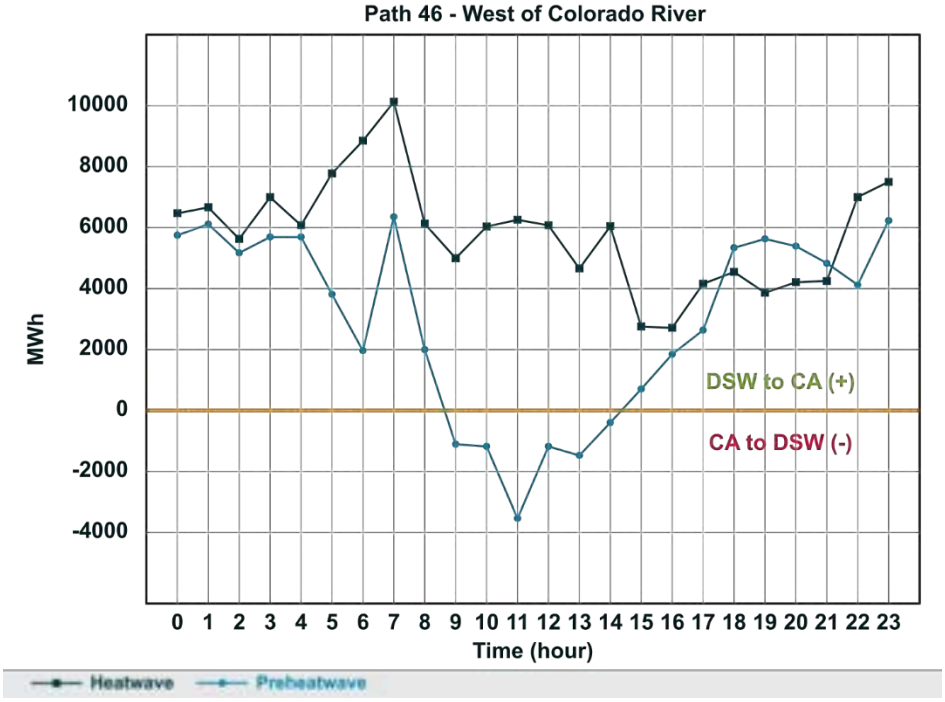


Figure 25. Hourly power flows during the heatwave and preheatwave days for Path 46

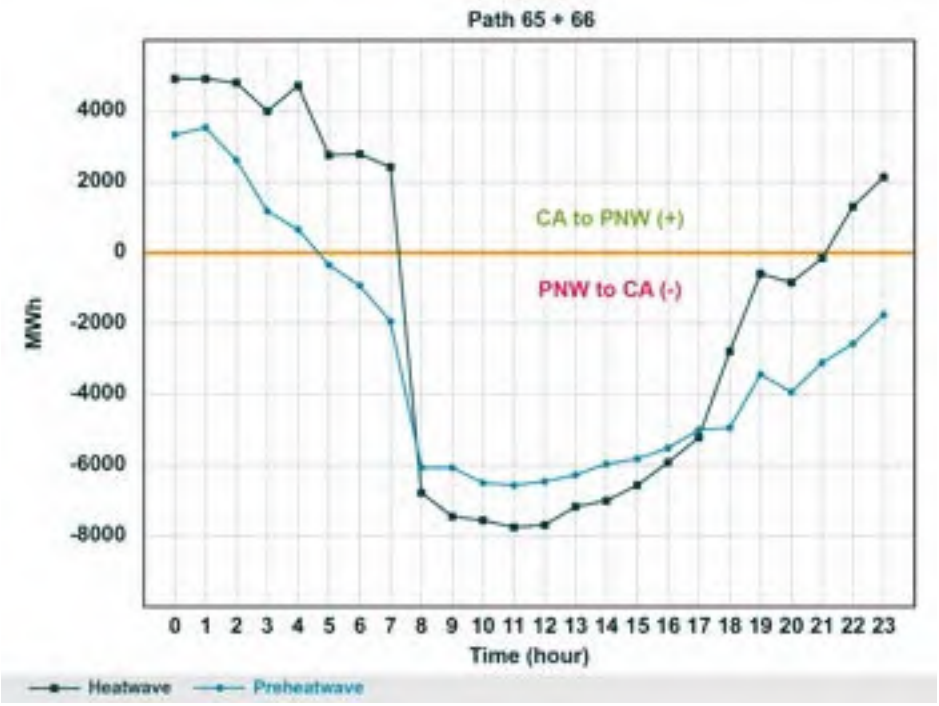


Figure 26. Hourly power flows during the heatwave and preheatwave days for Paths 65 (Pacific DC Intertie) and 66 (California Oregon Intertie)

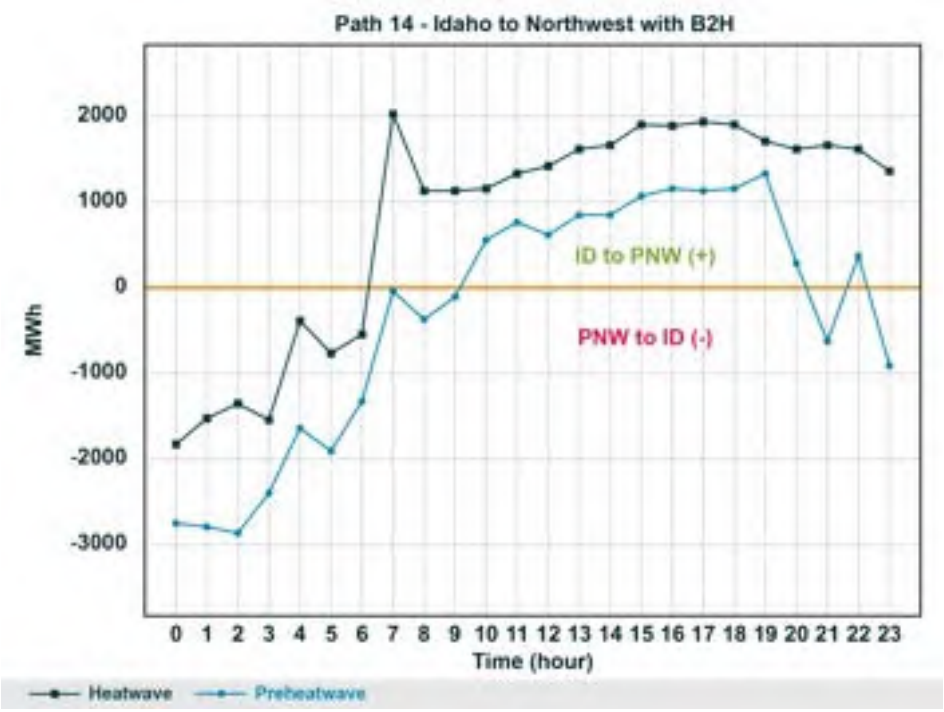


Figure 27. Hourly power flows during the heatwave and preheatwave days for Path 14

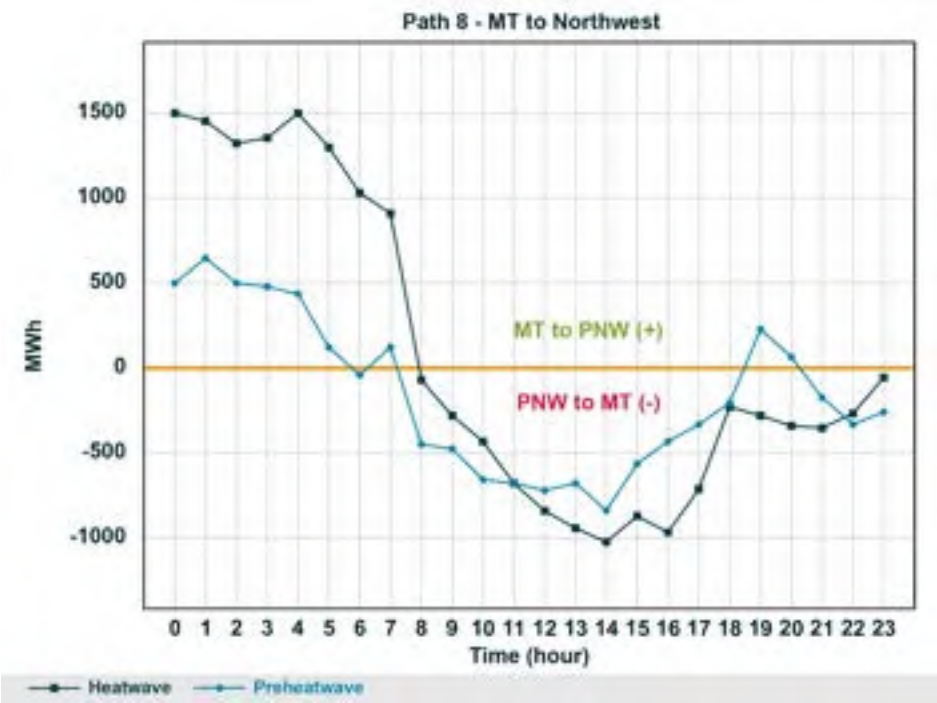


Figure 28. Hourly power flows during the heatwave and preheatwave days for Path 8

In summary, during the combined California heatwave event and PNW drought, all examined interfaces contribute to supporting California by increasing imports—particularly in the early morning hours—to address the challenges of load ramp and capacity shortfalls. In addition, California's exports rise during solar generation hours, both to PNW (via Paths 65 and 66) and to the Desert Southwest (WestConnect) via Path 46.

Figure 29 shows the impact of interregional transmission lines supplying California and PNW in mitigating unserved energy.

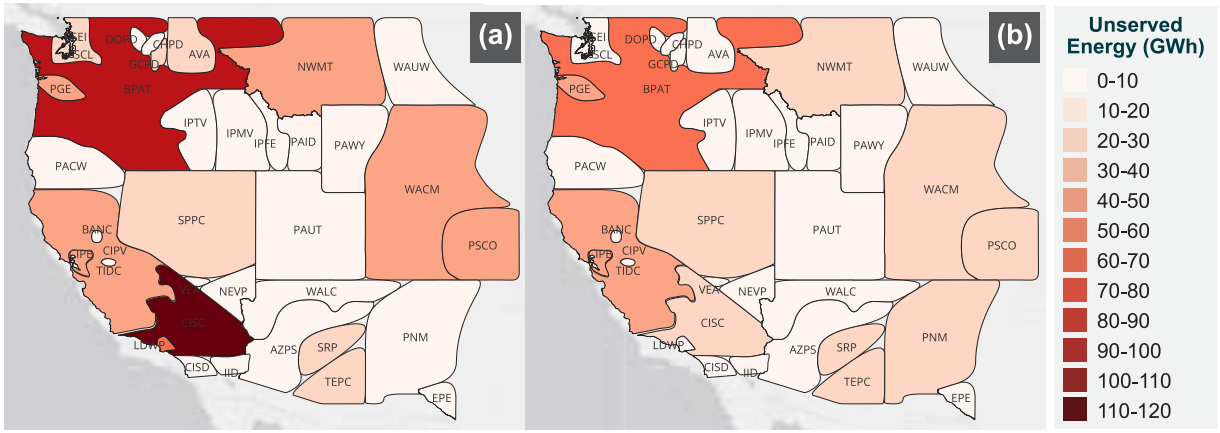


Figure 29. Total unserved energy (GWh) by load area during the combined California heatwave and PNW drought for the Lim scenario (a) and AC scenario (b)

## 4.4 Transmission and Resource Planners Should Carefully Consider the Interregional Transmission Capacity and Additional Local Generation Capacity When Minimizing Risks of Extreme Stress Events

The combined heatwave and drought in PNW resulted in lower unserved energy in California under the Limited scenario than under the AC scenario. In these two scenarios, when the traditionally exporting region (PNW) was affected by compounding extreme events, the scenario with greater local dispatchable generation and storage capacity within the importing region (California) resulted in greater shortfall mitigation. This outcome suggests attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation and transmission availability differently. Hence, planning studies must carefully consider the attributes of extreme events when considering the topology and capacity of transmission, generation, and storage solutions—whether local or interregional.

This behavior is conceptually shown in Figure 30b. Traditionally, during nonstress periods, PNW primarily serves as a net exporter, leveraging its hydroelectric power resources, while California stands out as a high-demand net importing region (EIA 2023). However, when PNW faces a combined heatwave and drought event, it becomes a net importer (Figure 30b). In such conditions, all neighboring regions strive to assist PNW, whose hydroelectric production is reduced, and almost all PNW

generation capacity is allocated mainly to supply the local increased demand. As a result, the new interregional capacity that is present in the AC scenario (Figure 22) and mainly connects the Desert Southwest to California becomes insignificant in supporting California's demand. In contrast, California's greater self-sufficiency in local dispatchable generation capacity (as in the Lim scenario) (Figure 16) might prove more advantageous in mitigating unserved energy in the state.

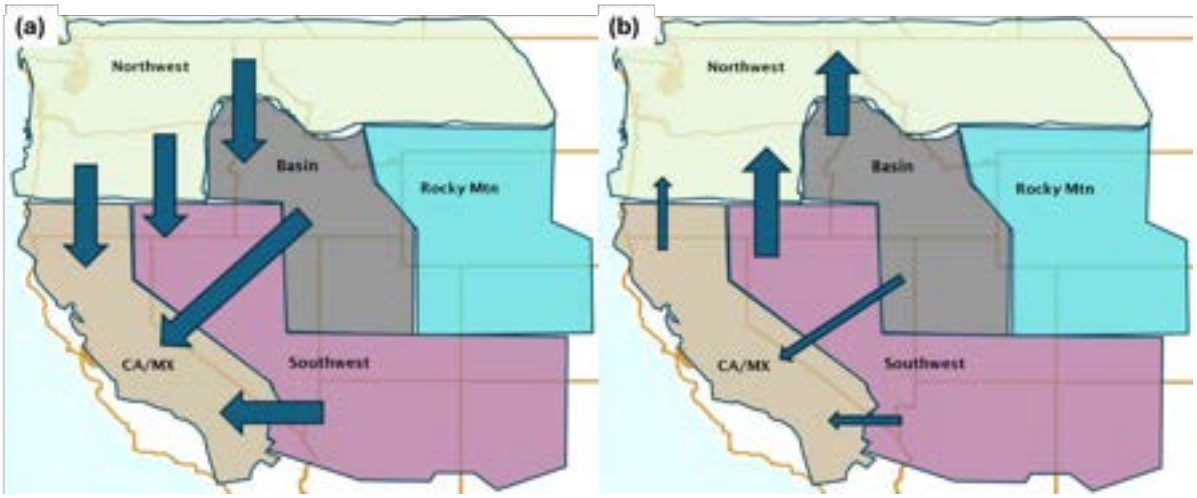


Figure 30. Conceptual representation of net power flows for the Lim scenario during nonstress grid operations (a) and during extreme stress operations when PNW is experiencing a combined heatwave and drought event (b)

*The width of the arrow represents the magnitude of the flow, with a larger width indicating higher flows.*

Figure 31 depicts the interplay between supplementary transmission capacity (AC scenario) and additional local generation capacity in California (Limited scenario) during the combined PNW heatwave and PNW drought. As expected, the additional installed capacity of local flexible resources such as storage and natural gas (gas turbine [GT]) leads to higher use of these resources in the Limited scenario compared to the AC one, resulting in a 1.3% reduction of unserved energy in the California region, as shown in Figure 32. In contrast, the additional interregional capacity in the AC scenario does not appear to offer practical support to California because exports are comparable between the two scenarios. This suggests in both transmission scenarios, California becomes a net exporter to alleviate stress events in PNW. Consequently, the additional transmission lines proposed to connect the Desert Southwest with California, as suggested in the AC scenario, become underused.

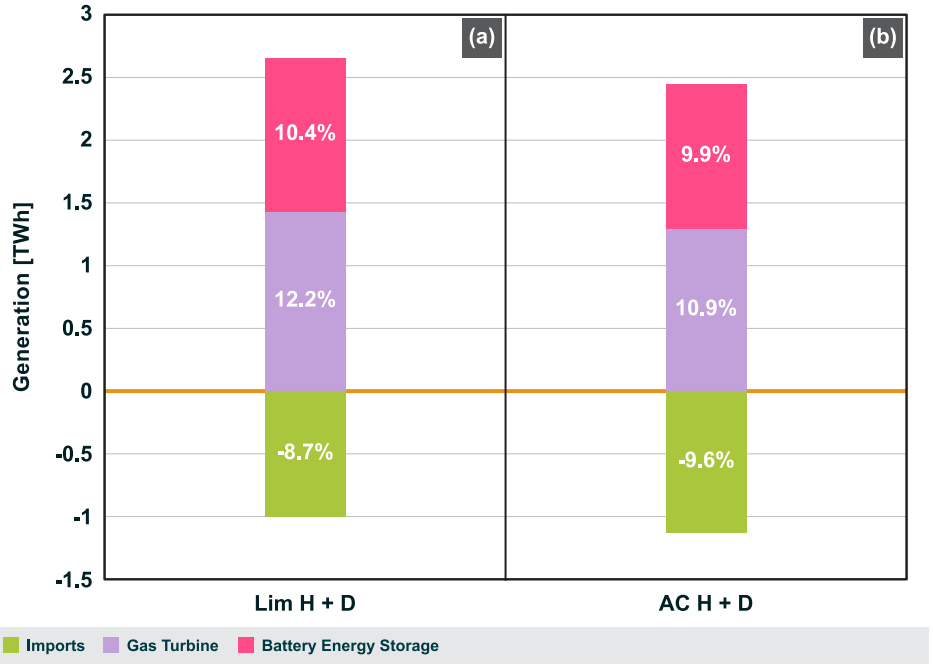


Figure 31. Generation outputs (TWh) in California for the Lim (a) and AC (b) scenarios during the combined PNW heatwave and PNW drought

*The Limited scenario shows higher amounts of BESS and GT use, which in turn has resulted in lower unserved energy in California compared to that for the AC scenario.*

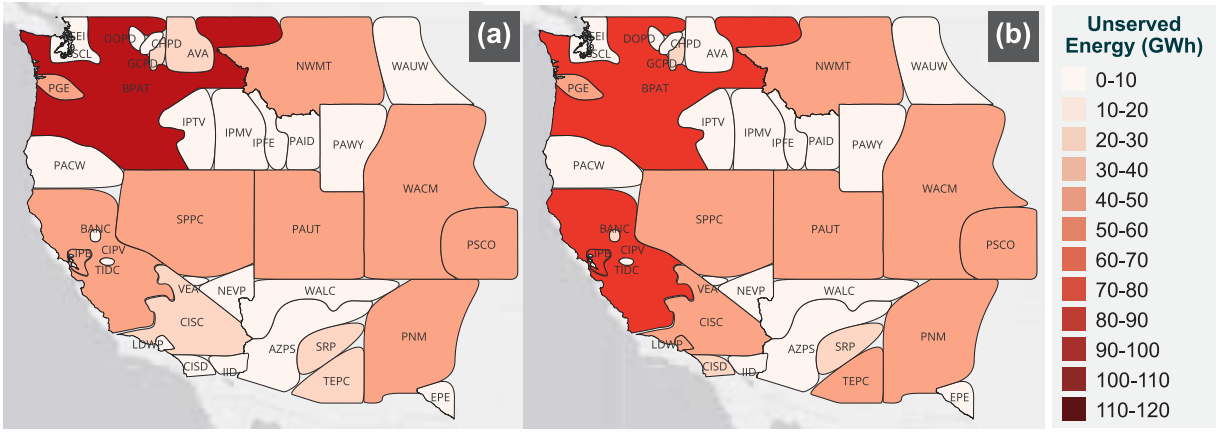


Figure 32. Total unserved energy (GWh) by load area during the combined PNW and PNW drought for the Lim (a) and AC (b) scenarios

## 4.5 Economic Impacts Differ Based on Transmission Topology and the Location, Type, and Intensity of Extreme Events

The study team compared the benefits of the Limited and AC transmission scenarios. To evaluate these benefits, the study team examined the differences in avoided costs of generation and the C-VOLL between the two transmission scenarios.

Table 2 shows the benefit of avoided generation costs for the two transmission scenarios across all stress events. The generation costs of the AC scenario are lower than those of the Limited scenario for all stress events because of a higher prevalence of low-cost renewable generation in the eastern portion of the Western Interconnection.

Table 2. The Benefit of Avoided Generation Costs Between the Limited and AC Scenarios: Additional Lower-Cost Renewable Generation Favors the AC Topology

| Stress Event | Lim Generation Cost ($B) | AC Generation Cost ($B) | Generation Cost Savings of AC ($B) |
|---|---|---|---|
| PNW heat | 16.2 | 15.4 | 0.7 |
| PNW heat + PNW drought | 17.6 | 16.9 | 0.7 |
| CA heat | 15.7 | 14.9 | 0.9 |
| CA heat + PNW drought | 17.2 | 16.4 | 0.8 |
| *Note: Results may not add because of rounding.* | | | |

Figure 33 shows the total C-VOLL costs (lower is better) for the two transmission scenarios across all stress events. During the single California heatwave event, the total C-VOLL costs for the AC scenario are lower than the costs of the Limited scenario ($107 billion Limited vs. $85 billion AC). During the combined California heatwave and PNW drought event, the AC scenario results in lower total C-VOLL costs than the Limited scenario ($268 billion Limited vs. $223 billion AC). During the single PNW heatwave event, the Limited scenario results in lower total C-VOLL costs than those of the AC scenario ($54 billion Limited vs. $64 billion AC). Similarly, during the combined PNW heatwave and PNW drought, the Limited scenario records lower total C-VOLL costs than the AC scenario ($156 billion Limited vs. $173 billion AC). Of note is lost load is present in all the extreme events modeled. Different transmission topologies were able to reduce the amount of lost load but not completely prevent it.

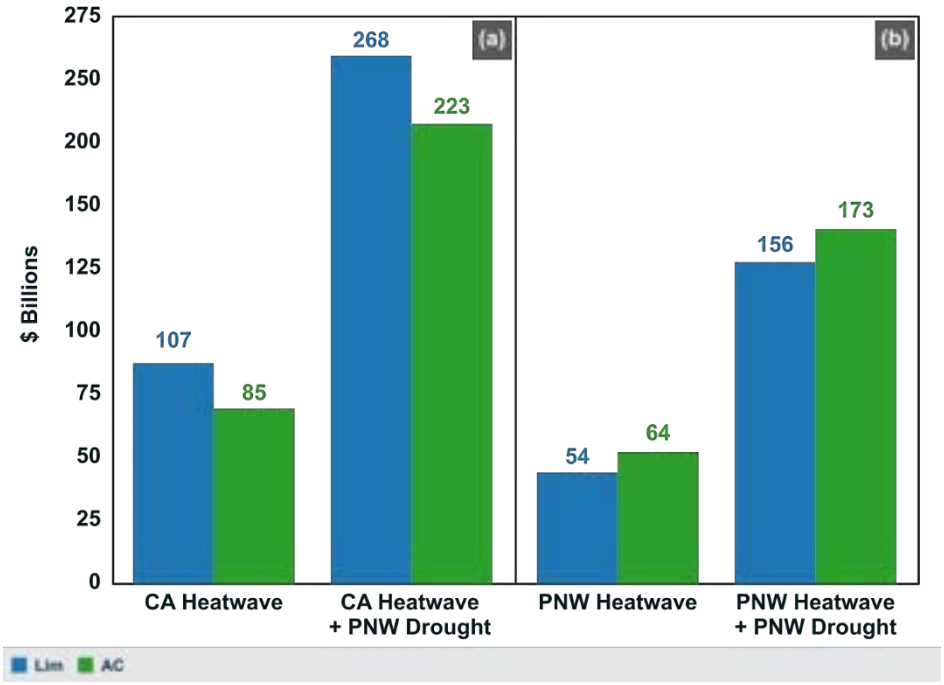


Figure 33. Total C-VOLL costs (TWh × $/TWh) by transmission topology across the Western Interconnection from the combination of a heatwave in (a) California or (b) PNW and the PNW drought compared to the respective single heatwave events.

Figure 34 displays the economic benefit of the AC scenario over the Limited scenario expressed as the difference in C-VOLL costs for each stress event. The AC scenario produces large improvements in total C-VOLL during the California heatwave and the California heatwave plus PNW drought events, with $21 billion and $45 billion less C-VOLL, respectively. The Limited scenario produces C-VOLL improvements during the PNW heatwave event and during the PNW heatwave and PNW drought event with $10 billion and $16 billion less C-VOLL in the Limited scenario.

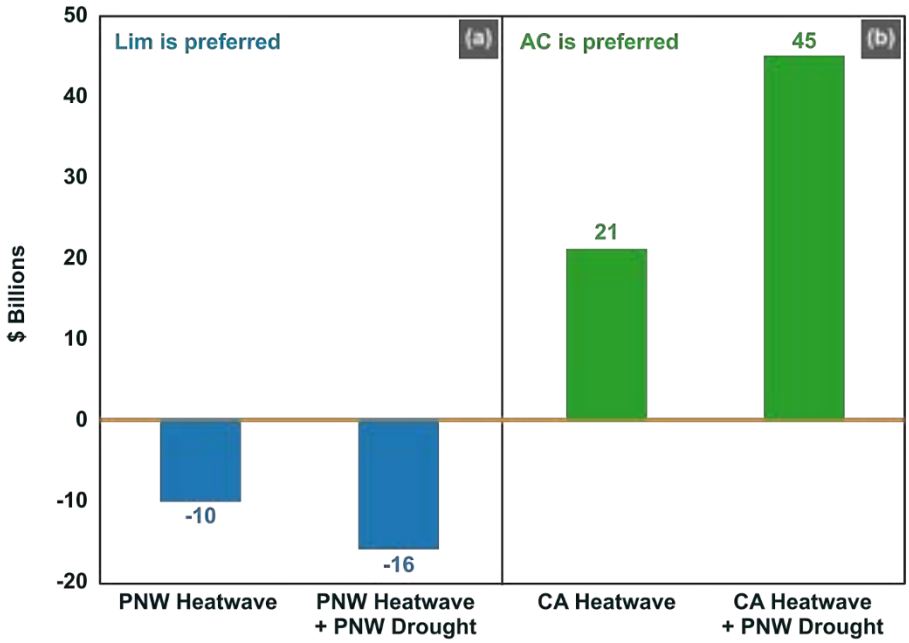


Figure 34. The economic benefit of the AC scenario over the Lim scenario expressed as the difference in C-VOLL

*Positive values indicate AC is preferred (a), and negative values indicate Lim is preferred (b).*

Comparing the magnitudes of the two benefits (i.e., avoided generation costs and C-VOLL costs), the differences in avoided generation costs (Table 2) are much smaller than the differences in the total C-VOLL costs, shown in Figure 34. This result indicates during extreme events, the end consumers' costs—which result from not serving the load—are much higher than the additional required generation costs. As such, the costs incurred from unserved load could play a critical role in the planning process for future transmission expansion plans.

# 5 Conclusions

The study team applied a suite of modeling tools for projecting extreme weather events onto future grid scenarios to assess the reliability, operational, and economic impacts of such stress conditions under different NTP Study nodal transmission expansion scenarios. By simulating these scenarios, the study team gained insights into how different regions might fare in the face of extreme events considering their unique generation mixes and the capacity for interregional energy transfers. The interplay between these factors is critical, highlighting the value of extreme event analysis in understanding the potential advantages of expanding transmission infrastructure. This approach underscores the need for strategic planning in the development of transmission capabilities across regions. The stress case analysis takeaways are as follows:

1. Compounded extreme events lead to higher levels of unserved energy than individual events. When the California or PNW heatwave is combined with the PNW hydropower drought, the resulting unserved energy increases in both regions and across both transmission scenarios.

    a. Specifically, in the Limited scenario, unserved energy rises to 3.8% and 7.7% for California and PNW, respectively, during the combined California heatwave and PNW drought, compared to the single California heatwave event, which results in 1.5% and 1.3% unserved energy for California and PNW.

2. The buildout of additional interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of unserved energy. This advantage is notably evident during the simultaneous California heatwave and PNW drought.

    a. The new interregional capacity (in the AC scenario) within the Western Interconnection region provides a vital corridor for channeling wind resources from New Mexico, Colorado, and Wyoming to meet the increased demand in California caused by the heatwave and reduced PNW hydropower imports. This strategic transmission route is vital in addressing California's surging demand during the heatwave and compensating for the shortfall in hydropower imports typically received from PNW. As a result, unserved energy is reduced by 1.5% in California (4.2% in Southern California) and 1.9% in PNW in the AC scenario compared to the Limited scenario.

3. Transmission and resource planners should carefully consider interregional transmission and additional local generation capacity when minimizing the risks of extreme stress events.

    a. Both interregional transmission and local generation capacity expansion are necessary to manage risk during a variety of extreme stress events,

as exemplified by the combined heatwave and drought in PNW. California has 1.3% lower unserved energy levels in the Limited scenario than in the AC scenario, benefiting from its greater installed capacity of local dispatchable resources (such as battery storage and natural gas) that could support the state's increased load demands amid decreased imports from PNW. In both scenarios, California is a net exporter, supporting the PNW heatwave and drought.

b. This specific case indicates the attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation availability differently, including the ability to transfer power between regions. Hence, depending on the extreme event under study, a system with different levels of interregional transmission capacity may respond differently based on the levels and types of generation and storage resources, including local assets. Therefore, transmission planning solutions will need to carefully consider the attributes of extreme events and how those affect the generation availability and transmission use.

4. Unserved energy peaks in the morning (5–8 a.m.) because of low online energy resource availability and increasing load ramps.

    a. The unserved energy peak coincides with increasing morning load ramp and exhausted battery and pumped hydro energy storage resources (because of the full use of storage to meet the peak load in the late afternoon when solar diminishes), prior to solar generation coming online. The amount of unserved energy is higher in the Limited scenario compared to the AC scenario, underscoring the importance of interregional capacity (in the AC scenario) in boosting California imports to meet the load during early morning hours.

5. Different transmission topologies provide varying economic benefits of reliability based on extreme event locations and types.

    a. The values shown in this chapter are based on four specific stress events (PNW heatwave, PNW heatwave with PNW drought, California heatwave, and California heatwave with PNW drought) with specific geographical region (California vs. PNW) and intensity characteristics. To understand the overall impact, a more comprehensive analysis including a variety of extreme events must be undertaken.

    b. For each stress event under study, the economic VOLL for these unserved energy periods were in the tens to hundreds of billions of dollars for individual regions (PNW or California). These values are significantly large in that they approach the total cost of the system expansion (transmission and generation) for the Western Interconnection through 2035 (see Chapter 3). However, the reader should be cautioned not to add the benefits presented here to other types of economic benefits or directly

compare the magnitude of these benefits with transmission capital costs. This highlights the importance of considering extreme scenarios in addition to the commonly used peak load projections to establish the proper design conditions for capacity expansion and transmission planning processes.

6. Future areas recommended for study could include the following topics:

    a. Conduct additional stress analyses for the Eastern Interconnection by itself as well as for the combined Eastern and Western Interconnection (MT-HVDC) scenarios under both compounded and single stress events. The combined study of the Eastern and Western Interconnections could provide valuable insights into the economic and reliability benefits of transmission planning across seams, allowing affected areas to tap into a more diverse array of generation resources spanning a larger geographic footprint and leveraging variations in time zones.

    b. Expand the range of extreme events considered, such as cold snaps, periods of wind and solar droughts, wildfires, and other potential stressors. By broadening the scope of these analyses, power system planners can gain a more comprehensive understanding of the resilience and vulnerabilities of their grid, informing more robust strategies for mitigating future disruptions and ensuring grid reliability.

    c. The NTP Study built the two nodal transmission expansion scenarios (i.e., AC and Limited) without considering extreme events. A future recommendation is to integrate geographical considerations and account for the magnitude and location of compounding stressors into transmission and generation capacity planning decisions. This stress-informed planning could help build a more robust power system, capable of withstanding a variety of extreme weather stressors.

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# Appendix A. Load Modeling

## A.1 Selecting Weather Events

The study team chose two unique and contrasting western U.S. heatwave events. The first occurred from roughly June 25, 2015, to July 2, 2015, and covered most of the western United States, including the Pacific Northwest (PNW). The second occurred from roughly July 22, 2015, to July 28, 2018, and was most intense over California and the Desert Southwest. Choosing two heat waves with different spatial extents allows the ability of expanded transmission to alleviate regional versus widespread stress to be tested.

The study team identified and characterized the weather conditions during these events using the Thermodynamic Global Warming (TGW) dataset generated by the Integrated, Multiscale, Multisector Modeling (IM3) project (Jones et al. 2023). The TGW data contains 40 years (1980–2019) of hourly historical meteorology (e.g., temperature and humidity) at a 12-kilometer (km) spatial resolution. Then, the study team repeated the 40-year historical record twice into the future (2020–2059 and 2060–2099) with various levels of additional warming applied to the boundary conditions of the Weather Research and Forecasting (WRF) model used to dynamically downscale the meteorology. The additional warming comes from the average climate model warming levels for two radiative forcing scenarios (Representative Concentration Pathways [RCPs] 4.5 and 8.5) and uses averages for climate models that are colder and hotter than the multimodel mean. This methodology allows historical weather events to be replayed in the future, providing a way to examine how significant historical events such as heatwaves may play out in a warmer future world.

For the 12-km historical and future meteorology data (Jones et al. 2023), the study team postprocessed the data by first spatially aggregating them to the county scale (Burleyson, Thurber, and Vernon 2023a); then, the study team weighted the county data by population to create hourly time series of the meteorology for each balancing authority (BA) in the United States (Burleyson, Thurber, and Vernon 2023b). Figure A-1 shows an example of the TGW temperature evolution in the California Independent System Operator (CAISO) BA.

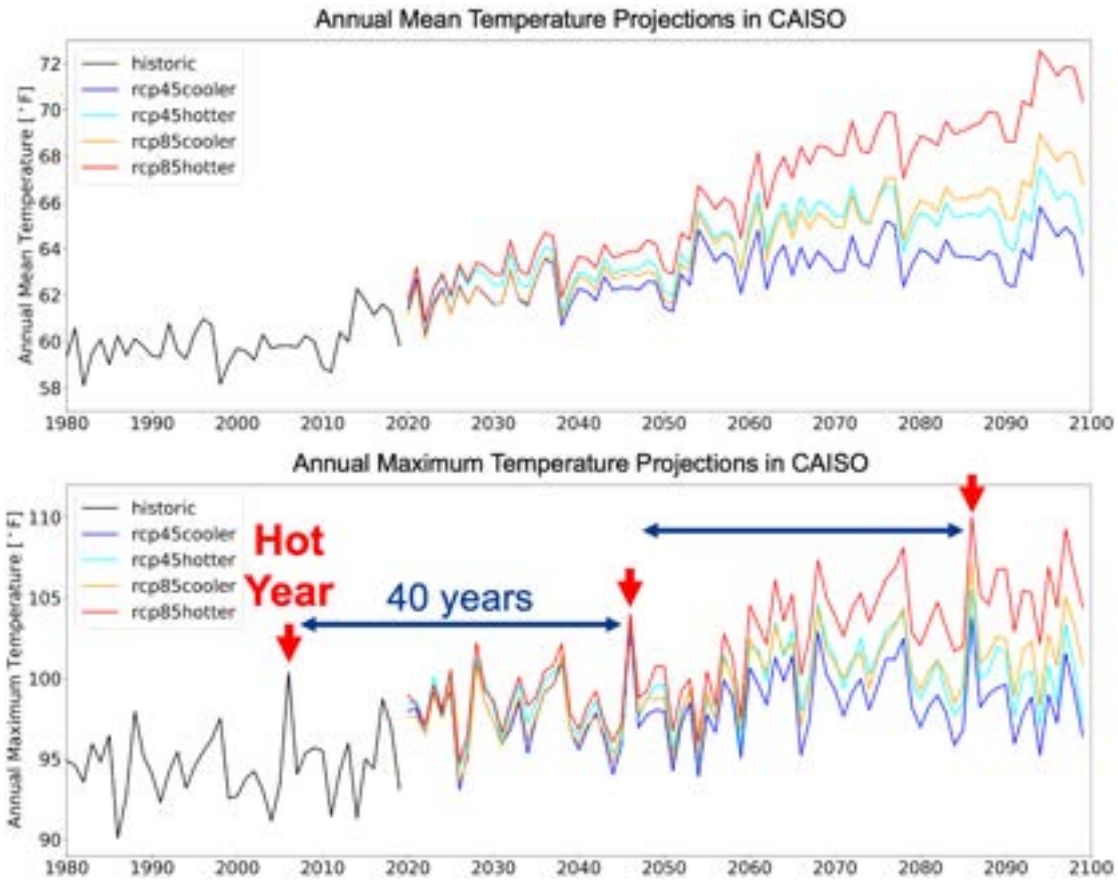



Figure A-1. Evolution of the annual mean (top) and maximum (bottom) temperatures in the CAISO BA service territory

*The black lines show the historical values (1980–2019), and the colored lines show the projected values under varying levels of climate change.*

In addition, in the heatwave stress analysis, the study team chose to include the effects of climate change on the projected loads. To factor in climate change, the study team used future weather years in the TGW dataset that included the additional thermodynamic deltas applied. That means for the 2015 weather year, the study team used the 2055 (i.e., +40 years) projected weather year meteorology data generated using the RCP 8.5 hotter scenario from the TGW data. For the 2018 weather year, the study team used the 2058 projected meteorology data. The study team intentionally chose to use the hotter scenarios from the TGW data to further stress the grid during the heatwave event. Figure A-2 shows the increase in maximum temperatures because of climate change in each BA during the 2015 and 2018 heatwave events. On average across all BAs, climate change increases the projected maximum temperature during the heatwave periods by +5.5°F and +6.6°F for the 2015 and 2018 NTP heatwave events, respectively. A small number of BAs experience maximum temperature increases approaching +10°F. As expected, no BAs fall below the 1:1 line.

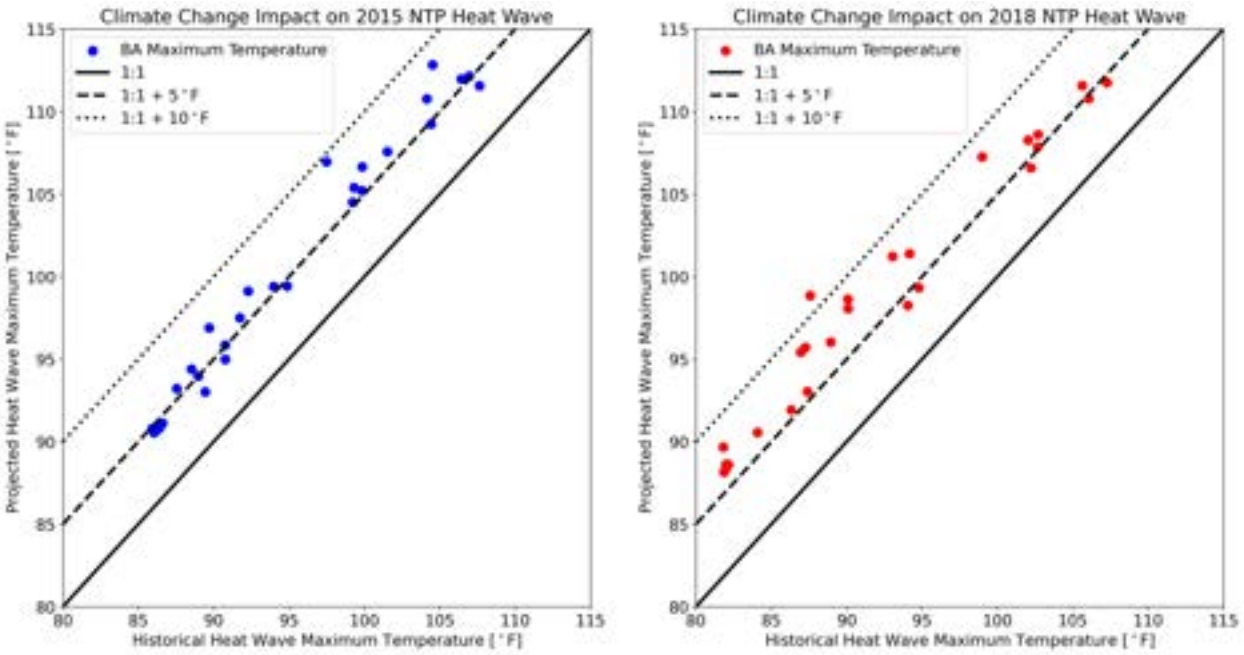



Figure A-2. Observed historical maximum temperature by BA (x-axis) during the 2015 (left panel) and 2018 (right panel) NTP heatwave events

*The y-axis shows the projected maximum temperature for the same events under climate change, as derived from the TGW weather dataset.*

## A.2 Load Projections

Once the study team selected the extreme events, the next step was to simulate how the hourly load, wind, and solar evolved over the course of the events. To do this, the study team borrowed a suite of models and techniques developed by other PNNL projects, including the IM3 project funded by the U.S. Department of Energy (DOE) Office of Science and PNNL's Grid Operations, Decarbonization, Environmental and Energy Equity Platform (GODEEEP) internal investment. The tool for simulating load is the extensively documented open-source Total ELectricity Loads (TELL; https://immm-sfa.github.io/tell/) model developed by IM3 (McGrath et al. 2022). TELL takes as input hourly time series of meteorology by BA and simulates the hourly evolution of the total electricity demand within the BA in response to the variations in weather.

TELL is a machine learning (ML)-based model trained on historical total weather and loads from 2016 to 2018. The historical total loads are from the Energy Information Administration (EIA)-930 dataset, which contains hourly total (net) load observations by BA going back to 2015. TELL trains a unique multilayered perceptron (MLP) model for each BA. The MLP models are accurate (see McGrath et al. 2022 and https://immm-sfa.github.io/tell/user_guide.html). The input variables for TELL are hourly time series of temperature, humidity, shortwave radiation, longwave radiation, and wind speed for each BA. The model also considers the time of day (in Coordinated Universal Time [UTC]), the day of the week, and whether the day was a federal holiday.

One minor thing to note is the load data that TELL was trained on include a slightly different set of BAs in the western United States from the BAs used in the GridView production cost model. TELL models the loads in CAISO, Idaho Power Company (IPCO), Nevada Power (NEVP), and PacifiCorp East (PACE) as a whole, but GridView separates them into subregions. To create the GridView data for these BAs, the study team used the entire BA load simulated by TELL and distributed it to the subregions within the BA using the fractional annual total load in each subregion to portion out the TELL loads. The study team calculated the fractional values using the 2035 National Transmission Planning Study (NTP Study) base year loads. In practice, this means the projected load time series in each of those GridView subregions will have the same temporal variations but different magnitudes. Table A-1 lists the subregions, which are also listed in the code repository containing the Jupyter notebooks used to run TELL for the NTP Study: https://github.com/cdburley/ntp_heat_wave_loads.

Table A-1. BAs in GridView That Do Not Directly Match What Is Simulated by TELL

| TELL Balancing Authority | GridView Subregions* |
|---|---|
| CAISO | CIPB, CIPV, CISC, CISD, VEA |
| IPCO | IPFE, IPMV, IPTV |
| NEVP | NEVP, SPCC |
| PACE | PAID, PAUT, PAWY |

*Abbreviations: CAISO = California Independent System Operator; CIPB = Pacific Gas & Electric Bay Area; CIPV = Pacific Gas & Electric Valley Area; CISC = Southern California Edison; CISD = San Diego Gas & Electric; IPCO = Idaho Power Company; IPFE = Far East (Idaho Power); IPMV = Magic Valley (Idaho Power); IPTV = Treasure Valley (Idaho Power); NEVP = Nevada Power; PACE = PacifiCorp East; PAID = PacifiCorp East – Idaho; PAUT = PacifiCorp East – Utah; PAWY = PacifiCorp East – Wyoming; SPCC = Sierra Pacific Power; VEA = Valley Electric Association

Because the NTP Study is considering a future projection of the electric grid (e.g., the grid as it may exist in 2035), the loads must be grown to reflect the natural long-term growth of energy demand between when the TELL MLP models were trained (2016–2018) and 2035. The study team implemented this growth by scaling the raw output from TELL to match the total annual energy for each BA in the base 2035 NTP loads. These 2035 annual energy values in NTP are based on the 2009 weather year. The goal of scaling to match the annual energy in each BA is to mimic the slow, long-term growth trends in loads that are not captured by TELL.

## A.3 Load Analysis

The projected loads based on the 2015 and 2018 weather years are not intended to be directly compared to the 2035 NTP Study base loads. They are based on different weather years with different heatwaves (both locations and magnitudes) and use fundamentally different methodologies to project the loads forward to 2035. However, the study team performed basic analyses of the changes in the minimum and maximum loads to provide a basic understanding of the differences in the base case loads and the heatwave loads that were intentionally designed to stress the system.

Figure A-3 shows the annual minimum and maximum loads by BA for the 2015 and 2018 weather years compared to the 2035 base case values. The solid, dashed, and

dotted lines show the 2035 base case values ±0%, ±10%, and ±20%. Across all BAs, the annual minimum loads using the TELL projection methodology are all within ±20% and are most often within ±10% of the 2035 base case values. The same is mostly true for the annual maximum loads, which tend to be (by design) higher using the TELL methodology but still generally comparable to the 2035 base case values, which were derived for a different weather year and do not include the amplification of loads because of climate change. The largest differences are on the order of +20%.

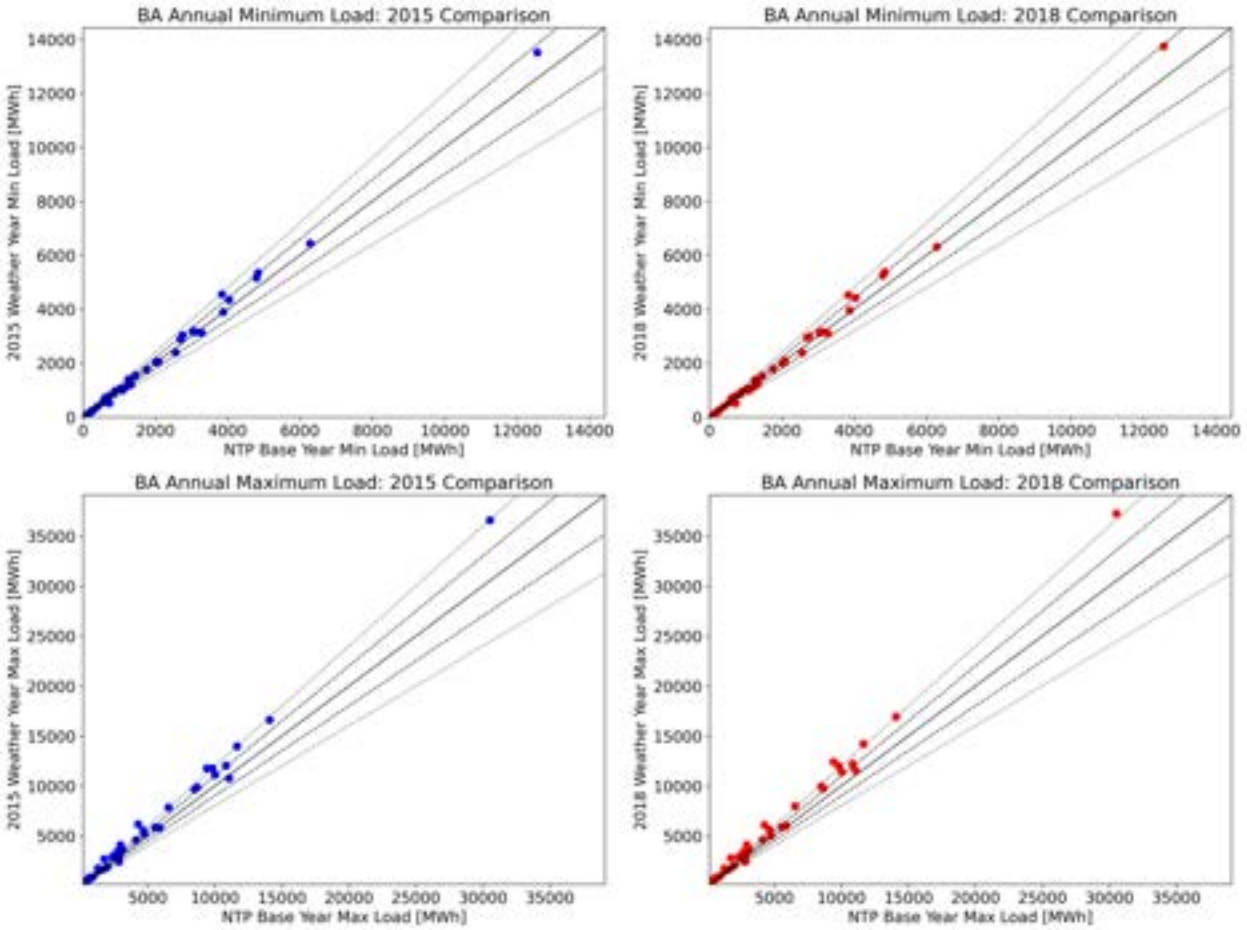



Figure A-3. Scatterplots showing the relationship between the annual minimum (top row) and maximum (bottom row) load values by BA

*The study team derived the x-axis values from the 2035 NTP Study base year loads. The y-axis values are those derived from the 2015 (left column) and 2018 (right column) weather year loads with climate change. In each plot, the solid line shows a 1:1 relationship, and the dashed and dotted lines show 1:1 ±10% and 1:1 ± 20%, respectively.*

*MWh = megawatt-hour*

The methodology used by the study team also allows the impact of climate change on loads to be decomposed. By comparing the output of TELL from the 2015 and 2018 weather years without climate change to those with the climate change signal added, the impact of the decision to include climate change on the load projections can be quantified. Figure A-4 shows the load time series from TELL with and without the climate change impact included. Ignoring the spurious signals every 7 days because of

differences in weekdays and weekends between 2015 and 2035, the dominant (and expected) signal is for lower wintertime loads and higher summertime loads when using the weather data with the climate change signal included. The absolute difference is approximately −5,000 to −10,000 MWh in the winter and approximately +5,000 to +10,000 MWh in the summer. This corresponds to about a 5%–7% suppression of loads in the winter and a 4%–5% enhancement of loads in the summer. A similar pattern emerges when analyzing the 2018 weather year (not shown).

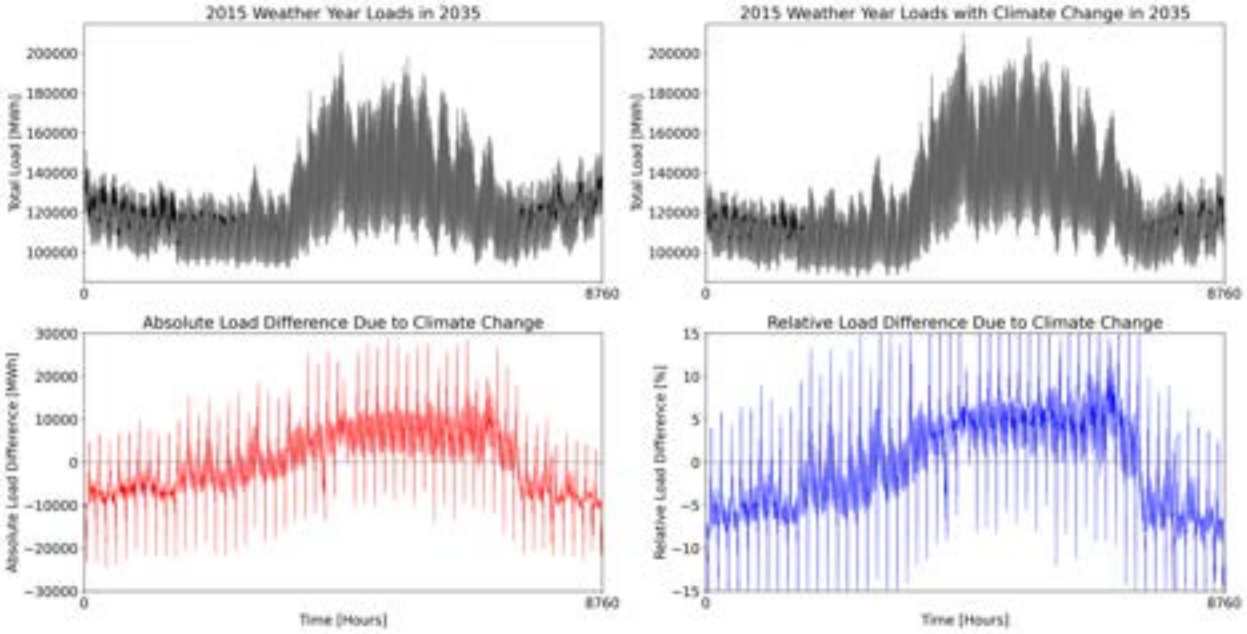



Figure A-4. Hourly loads in 2035 summed across all BAs in the western United States based on the 2015 weather year without (top left) and with (top right) climate change; the absolute difference between the two is shown in the bottom left, and the relative difference is shown in the bottom right

*Spurious positive and negative changes every 7 days are because of differences in weekdays and weekends between 2015 and 2035.*

# Appendix B. Wind and Solar Profiles

To develop hourly solar and wind profiles for the National Transmission Planning Study (NTP Study), the study team leveraged work by the Grid Operations, Decarbonization, Environmental and Energy Equity Platform (GODEEEP) project (http://godeep.pnnl.gov), which produced hourly wind and solar generation at every Thermodynamic Global Warming (TGW) grid cell. The study team performed the computation using the Perlmutter system at the National Energy Research Scientific Computing Center (NERSC), which was supported by the Integrated, Multiscale, Multisector Modeling (IM3) project. At every 1/8th degree grid cell, the study team extracted relevant meteorological data and preprocessed these data for use with the National Renewable Energy Laboratory (NREL) Renewable Energy Potential (reV) model (Maclaurin et al. 2021). reV is an interface to the System Advisor Model (SAM)—a collection of models for renewable energy. The study team used generic configuration options, such as a commonly used turbine hub height and panel array type, to describe the hypothetical power plant in each grid cell. Because of the way the study team constructed the TGW data with the historical period being replicated twice with additional warming applied, the future wind and solar years used here were 2055 and 2058. The study team used the RCP 8.5 hotter warming scenario to represent the most extreme case for the grid and scaled the wind and solar data to remove alternating current (AC)/direct current (DC) losses prior to being imported into GridView. Figure B-1 presents a summary of the workflow methodology.

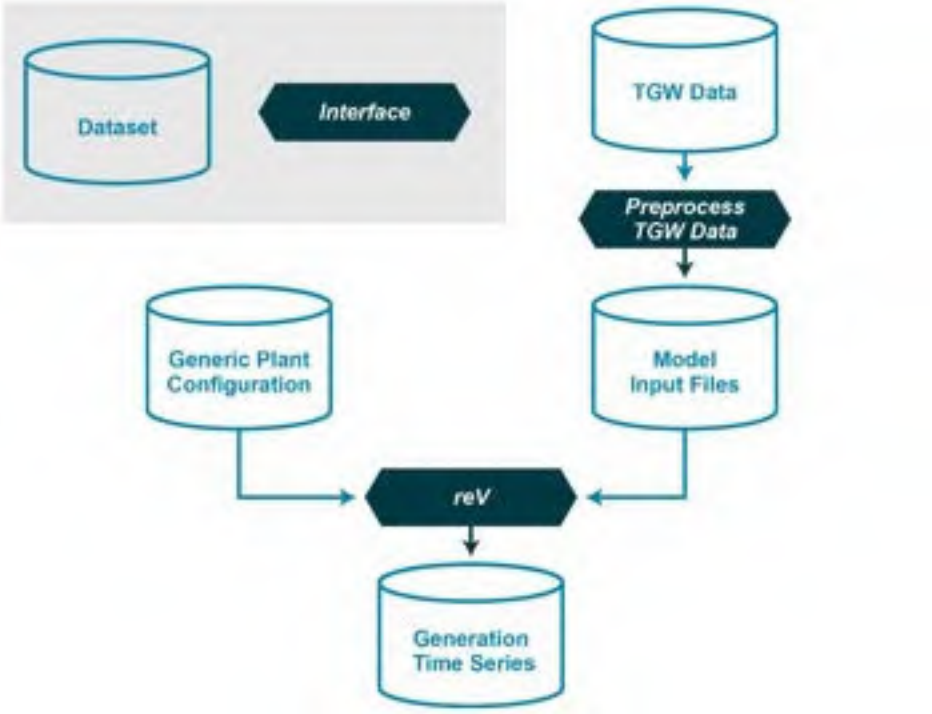


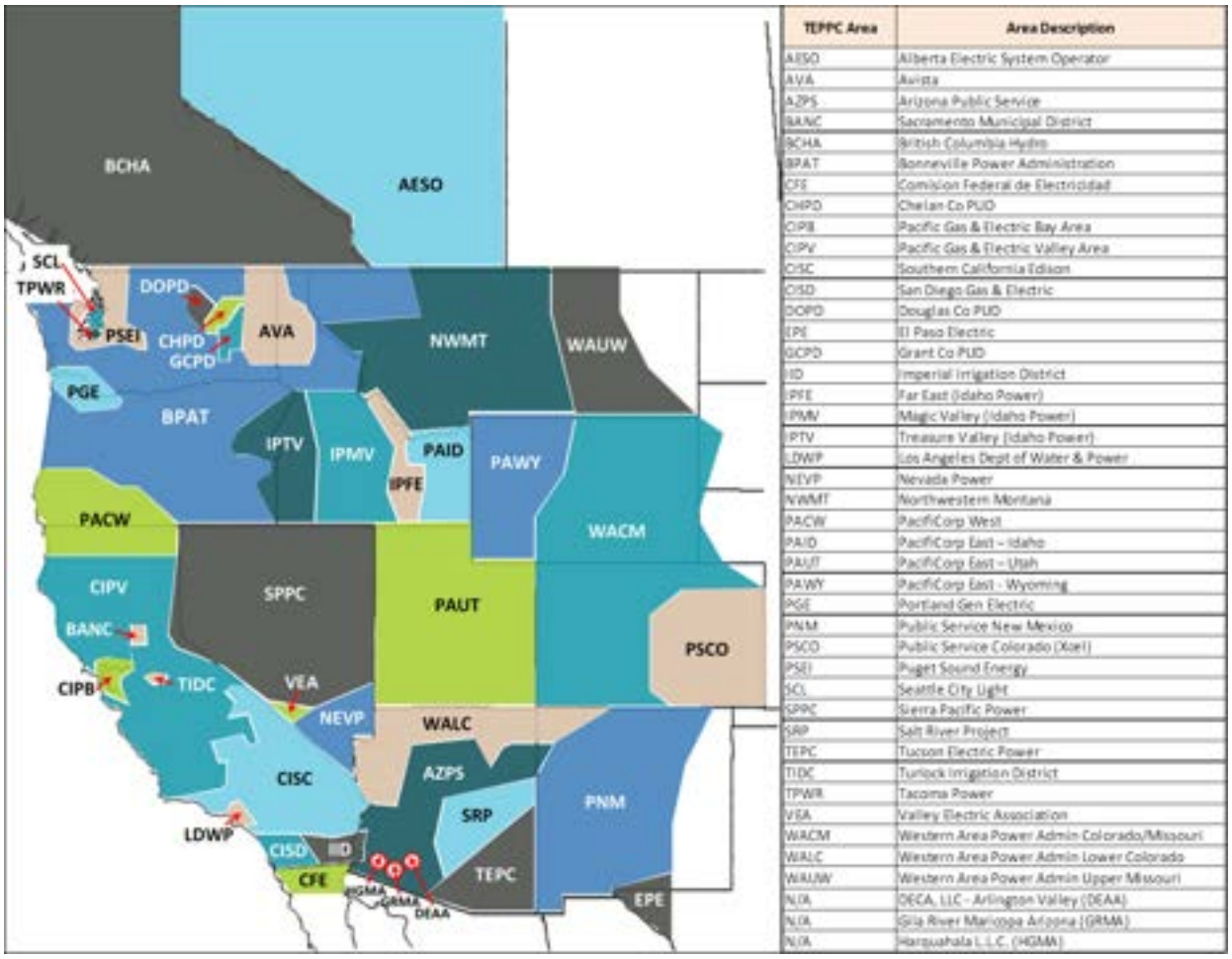

Figure B-1. Workflow for producing wind and solar generation data

*TGW is the meteorological dataset, and reV is the renewable generation model used.*

# Appendix C. Western Electricity Coordinating Council Load Areas

Figure C-1 shows the 40 load areas that, in most cases, are analogous to the balancing authority (BA) boundaries or the load-serving entity (LSE) (WECC 2020b). As previously noted, the study team incorporated the TELL heatwave loads from 2018 in California and 2015 in the Pacific Northwest (PNW) into the production cost model analysis for each respective load area. For presenting the unserved energy results of the production cost model for the stress case analysis, the study team grouped the following Western Electricity Coordinating Council (WECC) load areas to represent the California and PNW regions:

- The California region consists of the following eight WECC load areas, defined in the figure: CIPV, BANC, CIPB, TIDC, CISC, LDWP, CISD, and IID. The CFE is the electric commission for the country of Mexico and is therefore excluded from the analysis.
- The PNW region consists of the following WECC load areas (also defined in the figure): SCL, TPWR, PSEI, DOPD, CHPD, GCPD, PGE, BPAT, and AVA. The study team excluded the Canadian authorities (BCHA and AESO) from the analysis.




| TEPPC Area | Area Description |
|---|---|
| AESO | Alberta Electric System Operator |
| AVA | Avista |
| AZPS | Arizona Public Service |
| BANC | Sacramento Municipal District |
| BCHA | British Columbia Hydro |
| BPAT | Bonneville Power Administration |
| CFE | Comision Federal de Electricidad |
| CHPD | Chelan Co PUD |
| CIPB | Pacific Gas & Electric Bay Area |
| CIPV | Pacific Gas & Electric Valley Area |
| CISC | Southern California Edison |
| CISD | San Diego Gas & Electric |
| DOPD | Douglas Co PUD |
| EPE | El Paso Electric |
| GCPD | Grant Co PUD |
| ID | Imperial Irrigation District |
| IPFE | Far East (Idaho Power) |
| IPMV | Magic Valley (Idaho Power) |
| IPTV | Treasure Valley (Idaho Power) |
| LDWP | Los Angeles Dept of Water & Power |
| NEVP | Nevada Power |
| NWMT | Northwestern Montana |
| PACW | PacifiCorp West |
| PAID | PacifiCorp East – Idaho |
| PAUT | PacifiCorp East – Utah |
| PAWY | PacifiCorp East - Wyoming |
| PGE | Portland Gen Electric |
| PNM | Public Service New Mexico |
| PSCO | Public Service Colorado (Xcel) |
| PSEI | Puget Sound Energy |
| SCL | Seattle City Light |
| SPPC | Sierra Pacific Power |
| SRP | Salt River Project |
| TEPC | Tucson Electric Power |
| TIDC | Turlock Irrigation District |
| TPWR | Tacoma Power |
| VEA | Valley Electric Association |
| WACM | Western Area Power Admin Colorado/Missouri |
| WALC | Western Area Power Admin Lower Colorado |
| WAUW | Western Area Power Admin Upper Missouri |
| N/A | DECA, LLC - Arlington Valley (DEAA) |
| N/A | Gila River Maricopa Arizona (GRMA) |
| N/A | Harquahala L.L.C. (HGMA) |

Figure C-1. WECC load areas (WECC 2020b)

*TEPPC = Transmission Expansion Planning Policy Committee*

# Appendix D. Western Electricity Coordinating Council Interface Paths

Figure D-1 illustrates all Western Electricity Coordinating Council (WECC) transmission paths (WECC 2007), with those analyzed highlighted in green.

Path 65 (Pacific DC Intertie) transfers electricity from Northwest (Celio substation) to Southern California (Sylmar substation). The PDCI line is a ±500-kilovolt (kV) direct current (DC) multiterminal system. This system is divided into the northern and southern systems; the demarcation point is the Nevada–Oregon border (NOB). The north-to-south limit is 3,220 megawatts (MW) whereas the south-to-north limit is 3,100 MW.

Path 66 (California–Oregon Intertie) consists of three transmission lines that interconnect Oregon with Northern California. The north-to-south limit is 4,800 MW whereas the south-to-north limit is 3,675 MW.

Path 46 (West of the Colorado River) interconnects southern Nevada and Arizona with Southern California and is a key corridor for importing electricity to Southern California. It consists of 12 transmission lines and has an 11,200-MW transfer limit.

Path 14 (with Boardman to Hemingway [B2H]) connects eastern Oregon (Northwest) with southwestern Idaho. It consists of five transmission lines including the new B2H line. It has an east-to-west transfer limit of 2,400 MW and a west-to-south transfer limit of 1,340 MW.

Path 8 connects western Montana and the Northwest United States. The 10 lines involved in this path have an east-to-west transfer limit of 2,200 MW and a west-to-east transfer limit of 1,350 MW.

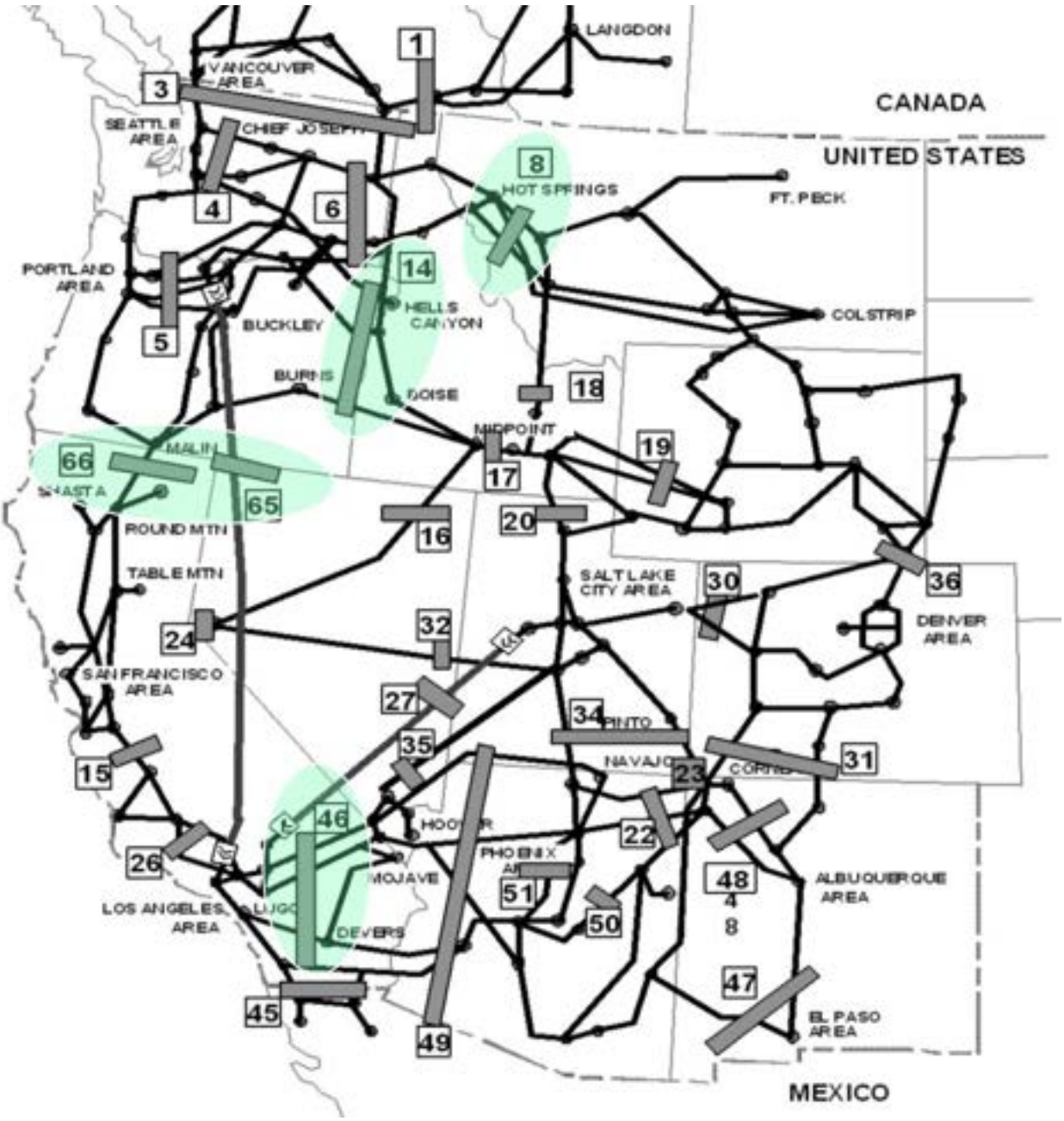



Figure D-1. WECC transmission paths (WECC 2007)

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# National Transmission Planning Study

## Chapter 6:

# Conclusions

NREL
Pacific Northwest NATIONAL LABORATORY
GDO GRID DEPLOYMENT OFFICE

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- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions (this chapter)** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

# List of Acronyms

| | |
|---|---|
| AC | alternating current |
| $CO_2$ | carbon dioxide |
| CONUS | contiguous United States |
| DOE | U.S. Department of Energy |
| HOT | High Opportunity Transmission |
| HVDC | high-voltage direct current |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| PNNL | Pacific Northwest National Laboratory |
| TRC | technical review committee |

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# 1 Background

Transmission is a critical part of the U.S. electricity system that has attracted increased attention recently because of several emerging trends. The generation resource mix is shifting to more geographically distributed and lower-emissions technologies, extreme weather events are becoming more frequent and have led to a reevaluation of resource sharing across regions, and electricity demand will likely increase—all of which create planning uncertainties in the coming decades.

The National Transmission Planning Study (NTP Study) was initiated to better understand the role, value, and opportunities for transmission across the bulk power system in the contiguous United States (CONUS). The NTP Study aims to inform regional and interregional transmission planning processes and identify transmission opportunities that will provide broad-scale benefits to electricity customers. To do this, the NTP Study applied a novel framework for considering the U.S. transmission system from a holistic perspective.

Several advances in the NTP Study make its technical approach unique to those of other studies. Notably, the study linked models often used in disparate transmission planning processes within industry through an ambitious multimodel analytic framework. The NTP Study is distinct from other studies and planning activities in three primary ways:

- The NTP Study inherently included interregional transmission because it used a national perspective. Interregional transmission solutions are not often included in bottom-up planning actions taken by existing transmission planning organizations. However, without a national or multiregional perspective, stakeholders may miss viable transmission expansion opportunities that can lead to significant potential systemwide savings.
- The NTP Study considered business-as-usual and ambitious scenarios that push decarbonization beyond the current emissions policies for many regions around the country. By taking this approach, the study team explored a broader set of technologies and captured a combination of factors and opportunities than is typically considered in industry planning.
- By integrating multiple models and planning aspects, the NTP Study provides a comprehensive view of transmission alongside generation and storage technologies. This approach enables the identification of more value streams and reliability benefits of transmission than are typically considered in transmission planning.

To validate the NTP Study approach, the team conducted extensive and varied stakeholder engagement with a wide variety of stakeholders. This included public meetings; a technical review committee (TRC) comprising a modeling subcommittee, a government subcommittee, and a land use and environmental exclusions subcommittee; coordination with existing convener groups; and Tribal outreach. The study team’s core premise was that a broad set of stakeholders should be involved throughout the study to shape objectives, provide technical feedback and advice, and ensure study outcomes answer the industry’s most pressing questions.

# 2 Key Findings

The NTP Study demonstrates different transmission expansion frameworks offer an array of reliability and cost benefits—both under a current policies framework and as systems reach higher levels of decarbonization. When interregional and regional transmission are evaluated simultaneously, additional opportunities emerge that further increase the benefits of transmission by enabling access to a diverse set of resources, including more geographically dispersed low-cost clean energy.

Following is a summary of the key findings across the four technical chapters of the NTP Study (Chapters 2–5).

Under current policies…

**The lowest-cost U.S. electricity system portfolios that meet future demand growth and reliability requirements include substantial expansion in transmission.**

- The total transmission system of the contiguous United States expands 2.1 to 2.6 times the size of the 2020 system by 2050 and interregional transmission grows 1.9 to 3.5 times.
- Interregional coordination to meet resource adequacy, using both existing and new transmission, can save the U.S. electricity system hundreds of billions of dollars.
- Accelerating transmission deployment beyond historical rates reduces power system $CO_2$ emissions by 10 to 11 billion metric tons (43% to 48%) through 2050.
- The amount of transmission expansion and the emissions savings from transmission scale with the level of electricity demand.

Under a U.S. electricity system carbon target that achieves a 90% greenhouse gas emissions reduction by 2035 and 100% by 2050…

**The study finds hundreds of billions of dollars of net benefits from large-scale transmission expansion compared to historic rates of transmission deployment.**

- Accelerated transmission expansion leads to national electric system cost savings of $270–490 billion through 2050.
- Incremental investments in transmission are more than compensated for by reduced electric system costs for fuel, generation and storage capacity, and other costs. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission.

- The benefits of transmission expansion to system costs scale with the level of electricity demand and rate of decarbonization.

**A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits across a wide variety of scenarios.**

- The United States transmission system expands 2.4 to 3.5 times the size of the 2020 system by 2050.

- Transmission expansion occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country.

- The use of high-voltage direct current (HVDC) transmission technologies, including advanced multiterminal converters, results in the greatest benefits to consumers across the transmission options studied.

- The largest benefits of transmission are realized when interregional transmission is most substantial, including building across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6 to 4.6 times the 2020 capacity by 2050.

- Constraining transmission growth results in higher cost portfolios with more nuclear generation, hydrogen, and carbon capture capacity required especially when carbon emissions are limited.

**Grid reliability can be maintained in future low-carbon grid scenarios with the lowest-cost solutions relying on coordinated transmission utilization between regions during periods of greatest stress.**

- All 96 modeled future grid scenarios in the study—including those with about 90% of annual generation from variable resources—meet or exceed resource adequacy standards.

- When transmission regions coordinate to achieve resource adequacy, system costs through 2050 are lowered by $170–380 billion. In scenarios that allow coordination, transmission is used bidirectionally across many regional interfaces to support resource adequacy.

- High-resolution grid simulations demonstrate hourly demand and supply can be balanced in power systems with very high shares of renewable energy. In scenarios with larger transmission expansion, imports and exports between regions play a substantial role in helping grid operators balance supply and demand in all hours.

- Power flow analyses specific to the Western Interconnection demonstrate highly decarbonized systems can withstand selected typical contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies.

- An analysis of four extreme event stress cases in the Western Interconnection, showed that in some cases the buildout of additional interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of power shortages.

**The NTP Study identifies several examples of transmission investment that could be promising candidates for more in-depth consideration by planners and developers.**

- High Opportunity Transmission (HOT) interfaces represent transmission capacity expansion results between regions across many scenarios. Transmission projects that align with these HOT interfaces could be strong candidates for further study and serve as a starting point for accelerated transmission expansion.

- Transmission portfolios that deliver broad-scale benefits to consumers were developed using laboratory and industry tools. These transmission portfolios demonstrate new interregional transmission combined with intraregional transmission upgrades can help meet the flexibility requirements of high renewable energy power systems.

Regardless of future policy, market, and technology conditions…

**Grid planning at the national or multiregional scale requires enhanced institutional coordination, accessible data, and new grid modeling approaches, which have advanced under the NTP Study in partnership with technical and planning experts.**

- Advancing grid models—merging siloed planning processes, facilitating translations between models, and overcoming computational barriers—is critical to analyzing transmission comprehensively and capturing transmission's multifaceted impacts.

- Additional data on potential extreme events, technology advancements, and demand uncertainty will support robust transmission and reliability planning to identify the best expansion opportunities for consumers under changing conditions. Data access enables broader participation and collaboration.

The identified benefits and expansion opportunities assume coordinated planning and use of transmission that goes beyond current practices. Developing guidelines for

planners or a framework for coordination between numerous stakeholders can help realize these benefits.

The findings in this study highlight many advantages of a more coordinated approach to planning and deployment of transmission in the United States. These findings can be used by industry in transmission planning efforts, by regulators to better understand different utility investment options to achieve policy objectives, or by researchers and consultants as a starting point for further study.

# 3 Limitations and Caveats

The NTP Study made several advancements to be able to model the CONUS grid under nearly 100 potential future scenarios and produce transmission portfolios tested with highly detailed power system modeling. However, there are several limitations and important caveats to this approach:

- Within the time, computational, and resource limitations of the NTP Study, the study team did not analyze all future scenarios with a mix of demand, technologies, or policies used by the entire comprehensive multimodel suite for the study. Detailed power system modeling of a broader range of scenarios will increase confidence in the results.
- The diversity of regulations, standards, and market rules that may impact the operations of the grid are not fully represented in the models, which may limit the total number of benefits quantified in the study that are realized. In general, the NTP Study scenarios assume greater institutional and policy coordination than currently exists in U.S. power system operations.
- The detailed planning that happens in utilities and regional transmission planning processes is beyond the scope of this study. Therefore, any solutions identified in the NTP Study may not be directly applicable to an area or region given the many additional details, such as transmission line siting and local physical constraints, that comprise regional and utility planning.
- Certain technologies, such as carbon capture and storage and hydrogen-fueled generation, which are abundant in modeling in the later years in the decarbonization scenarios (2040–2050), are not commercially widespread today. Though progress is being made in developing these technologies, uncertainty remains as to when they will be commercially available and at what cost.
- Given time constraints, the extreme event analysis conducted for this study considers only two different heatwaves and a drought in the Western Interconnection. It does not evaluate the full range of extreme events that could occur throughout the country, such as cold snaps in Texas and severe storms along the East Coast of the United States. The results presented here demonstrate the types of benefits that transmission can provide in extreme events, but conclusions cannot be drawn for all extreme events throughout the country. More work is needed in this area.

The study team evaluated reliability in several ways within the modeling framework, but they did not undertake NERC-level reliability assessments (North American Reliability Corporation n.d.). For this and other reasons, the solutions presented in this study are not prescriptive but rather indicative of the opportunities for transmission expansion in the U.S. grid. Follow-on studies could address some of these limitations, as could industry and other researchers applying NTP Study findings and data within their own planning and study frameworks.

# 4 Future Work

The NTP Study addresses a wide range of questions about the role of transmission in the bulk power system in CONUS, along with the reliability and cost benefits that can be gained through accelerated transmission expansion. However, a national-scale, interregional transmission planning effort of this scope is a significant undertaking—and there are several questions that either lie outside the scope of this analysis or require further investigation. The Grid Deployment Office intends to continue to lead national-scale grid planning efforts by developing enhanced institutional coordination, accessible data, and new grid modeling approaches in partnership with technical and planning experts. The Grid Deployment Office also intends to work with industry to put the findings and tools developed in the NTP Study into action in ongoing planning processes at the state, regional, and interregional levels. Future work could include the following:

- **Transmission siting.** Transmission network data available for the NTP Study are limited in that detailed rights-of-way information and other transmission infrastructure details (age of conductors, tower type, and so on) that could lead to more refined solutions for transmission expansion are not readily available. Additional analysis on the location and routing of transmission—and integration back into planning models—will build confidence in potential transmission solutions. Though not a focus of this study, future in-depth consideration of promising transmission options should include careful consideration of environmental, health, and community impacts and options.
- **Reliability and resilience.** The NTP Study team analyzed several aspects of reliability and resilience, including resource adequacy, contingency analysis, stress analysis, and system flexibility required for reliable operations. These elements of reliability should be further studied—particularly analysis of reactive power coordination, dynamic simulations and frequency response, and voltage ride-through during grid disturbances. In addition, though the NTP Study was able to evaluate discrete extreme weather events for the Western Interconnection, additional events should be studied to understand the role of transmission in mitigating risks from extreme weather. Future analysis should consider different areas of the country, including across multiple interconnections and different types of singular and compounded extreme events.
- **Markets and operations.** The NTP Study nodal scenarios envisioned complete coordination between transmission regions in the system's operations. As highlighted by a companion report for the NTP Study, *Barriers and Opportunities To Realize the System Value of Interregional Transmission* (Simeone and Rose 2024), complete coordination is optimistic given the challenges with coordinating the use of existing interregional transmission. These challenges will likely be magnified if the amount of interregional transmission is substantially greater than it is today. Further work should take a closer look at how different levels of market and nonmarket and operational coordination can impact transmission's use and value.

- **Distribution of impacts.** The NTP Study included limited analysis of regional disaggregation of cost savings from accelerated transmission and relative impacts between producers and consumers. Rather, the analysis of costs and savings described in this report primarily applies to the contiguous U.S. electric system as a whole. Additional analysis is needed to assess who would gain the most benefits and who might incur greater costs. Expanding the distributional impacts assessment between the diverse producers and consumers, such as between different socio-economic classes and between generators and transmission, could better inform impacts of transmission expansion to individual households, equity and energy justice issues, and market design and cost recovery to incentive new infrastructure development. Furthermore, expanding the impacts beyond costs and greenhouse gas emissions would provide a more comprehensive evaluation of transmission expansion.
- **Enabling technologies.** The NTP Study considered several transmission technologies and used advanced methods to capture multiple value streams for transmission. However, additional considerations about the best technology to increase capacity between regions, such as reconductoring or the use of grid-enhancing technologies (e.g., dynamic line ratings and power flow control devices), were not studied in detail. Because many transmission additions in the coming decades are likely to include a combination of new transmission and grid-enhancing technologies, better capturing these trade-offs could be an important step in planning studies going forward. In addition, experience with HVDC technologies in the United States is limited, so opportunities exist to better integrate HVDC technology capabilities into system planning and operations.
- **Grid edge solutions.** The NTP Study did not explore all alternatives to transmission, including distributed resources and nonwires solutions. Energy efficiency, demand response, coordinated electric vehicle charging, virtual power plants, and other demand-side flexibility programs can play important roles in the energy transition. They can reduce the need for transmission and supply-side resources by reducing electricity demand, avoid the need for assets with low use, and help support resource adequacy and reliability. However, the scale of transformation in the NTP Study scenarios—especially the high-demand or decarbonization scenarios—will likely still require large-scale transmission expansion even with the implementation of these nonwires solutions. These solutions may have large impacts on certain regional needs, and further study can improve estimates of these needs.
- **Supply chains**. The NTP Study did not explore the availability of materials and infrastructure to meet the transmission and generation needs in the scenarios. Further study on the supply chains of critical infrastructure is important. HVDC technologies are of particular importance.
- **Policy options and coordination.** The NTP Study included binding state policies in the modeled scenarios and invited comments and vetting of the policy representations and assumptions to TRC Government Subcommittee members and other state policymakers and experts. Future modeling work should further

explore options to achieve emerging federal and state policy goals and targets. Future U.S. Department of Energy modeling and analysis activities should include convenings, modeling, and data to support regional and interregional coordination efforts.

In addition, there are operational and administrative lessons to be learned from a study of this scale:

- **External engagement.** Outside experts were crucial for providing input on the scope of the project and providing data and feedback. Deep engagement with state, regional, Tribal, and national entities is important for national-scale transmission studies going forward. A process for future national-scale studies that builds on the engagement process established in the NTP Study could help leverage lessons learned.
- **Data management.** Data management across many different models, inclusive of all three interconnections, was a huge challenge in the NTP Study. The study team developed new methods to manage and visualize the data with an emphasis on transmission networks, but more can be done to expedite study outcomes and increase accuracy. Specifically, ongoing dataset development outside of a study objective will enable studies on faster timelines and with more consistent inputs. Such dataset development could include model working groups that update data and models at regular intervals and in coordination with a broader stakeholder team and systematic processes so stakeholders understand expectations, outcomes, and timelines for updated datasets. Another important element of working with U.S. power system data is some aspects of it may have restricted access. Understanding these elements and coordinating stakeholders accordingly is an important and necessary step.

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DOE/GO-102024-6262 | October 2024

# National Transmission Planning Study

## Executive Summary

NREL | Pacific Northwest National Laboratory | GDO Grid Deployment Office

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| | |
|---|---|
| AC | alternating current |
| B2B | back-to-back |
| $CO_2$ | carbon dioxide |
| DOE | U.S. Department of Energy |
| FERC | Federal Energy Regulatory Commission |
| GDO | Grid Deployment Office |
| GW | gigawatt |
| GWh | gigawatt-hour |
| HOT | High Opportunity Transmission |
| HVDC | high-voltage direct current |
| kV | kilovolt |
| LCC | line-commutated converter |
| MISO | Midcontinent Independent System Operator |
| MT | multiterminal |
| MW | megawatt |
| MWh | megawatt-hour |
| NPV | net present value |
| NREL | National Renewable Energy Laboratory |
| NTP Study | National Transmission Planning Study |
| P2P | point-to-point |
| PNNL | Pacific Northwest National Laboratory |
| PNW | Pacific Northwest region of the United States |
| ppm | parts per million |
| SPP | Southwest Power Pool |

| | |
|---|---|
| TRC | technical review committee |
| VRE | variable renewable energy |

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# Study Findings

To understand the transformation needed to ensure the U.S. electric transmission system continues to reliably serve the nation's electricity customers as the power sector evolves and transitions to cleaner resources, the U.S. Department of Energy (DOE) Grid Deployment Office (GDO) partnered with the National Renewable Energy Laboratory (NREL) and the Pacific Northwest National Laboratory (PNNL) on the multiyear **National Transmission Planning Study (NTP Study)**. The study sought to:

- Develop new national-grid-scale planning tools and methods that can be used by industry, especially when planning for interregional transmission capacity needs
- Identify potential transmission solutions that will provide broad-scale benefits to electric customers under a wide range of potential futures
- Inform planning processes for regional and interregional transmission
- Identify interregional and national strategies to maintain grid reliability as the grid transitions, including to a reliance on low- and zero-carbon energy resources.

The interregional focus of the NTP Study helps fill a gap in transmission planning—which, by design, focuses on the regional needs within each regional transmission planning entity's boundaries—as performed by industry today. As DOE explained in the 2023 National Transmission Needs Study, additional investments in interregional transmission will support system reliability and lower overall consumer costs. Extreme events that cause power plant outages—such as hurricanes and winter storms—or large spikes in electricity demand—such as high air conditioning use during heat waves—are increasingly common, and their impacts on the power system can be widespread. Mismatch in generation and demand from extreme events can result in temporary power outages and high prices for consumers. When one portion of the system experiences generation shortfalls, another portion of the grid is likely to have excess generation capacity that can support those shortfalls—if there is sufficient interregional transmission to deliver that excess capacity to the area of need. Interregional transmission also supports the development of within-region transmission, which must be reinforced to reduce congestion and reliably deliver generated electricity across long distances.

The NTP Study combined innovative methods with state-of-the-art industry practices demonstrating a forward-thinking approach to understanding the role and value of transmission in future power systems. The national perspective of the study, which incorporates systemwide optimization, enables a holistic examination of transmission, assuming regulatory and institutional barriers are overcome. The study used a combination of tools—all under the principles of least-cost planning and maintaining power system reliability—to analyze multiple facets of transformative transmission expansion for the power system in the contiguous United States. External engagement with industry convener groups, a technical review committee (TRC), Tribes, and the

public provided valuable input throughout the study. The study's principal findings with related key takeaways are listed next.

Under current policies…

**The lowest-cost U.S. electricity system portfolios that meet future demand growth and reliability requirements include substantial expansion in transmission.**

- The total transmission system of the contiguous United States expands to 2.1 to 2.6 times the size of the 2020 system by 2050 and interregional transmission grows 1.9 to 3.5 times.
- Interregional coordination to meet resource adequacy, using both existing and new transmission, can save the U.S. electricity system hundreds of billions of dollars.
- Accelerating transmission deployment beyond historical rates reduces power system $CO_2$ emissions by 10 to 11 billion metric tons (43% to 48%) through 2050.
- The amount of transmission expansion and the emissions savings from transmission scale with the level of electricity demand.

Under a U.S. electricity system carbon target that achieves a 90% greenhouse gas emissions reduction by 2035 and 100% by 2050…

**The study finds hundreds of billions of dollars of net benefits from large-scale transmission expansion compared to historic rates of transmission deployment.**

- Accelerated transmission expansion leads to national electricity system cost savings of $270–490 billion through 2050.
- Incremental investments in transmission are more than compensated for by reduced electricity system costs for fuel, generation and storage capacity, and other costs. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission.
- The benefits of transmission expansion to system costs scale with the level of electricity demand and rate of decarbonization.

**A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits across a wide variety of scenarios.**

- The United States transmission system expands to 2.4 to 3.5 times the size of the 2020 system by 2050.

- Transmission expansion occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country.

- The use of high-voltage direct current (HVDC) transmission technologies, including advanced multiterminal converters, results in the greatest benefits to consumers across the transmission options studied.

- The largest benefits of transmission are realized when interregional transmission is most substantial, including when transmission is built across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6 to 4.6 times the 2020 capacity by 2050.

- Constraining transmission growth results in higher cost portfolios with more nuclear generation, hydrogen, and carbon capture capacity required especially when carbon emissions are limited.

**Grid reliability can be maintained in future low-carbon grid scenarios with the lowest-cost solutions relying on coordinated transmission utilization between regions during periods of greatest stress.**

- All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed resource adequacy standards.

- When transmission regions coordinate to achieve resource adequacy, system costs through 2050 are lowered by $170–380 billion. In scenarios that allow coordination, transmission is used bidirectionally across many regional interfaces to support resource adequacy.

- High-resolution grid simulations demonstrate hourly demand and supply can be balanced in power systems with very high shares of renewable energy. In scenarios with larger transmission expansion, imports and exports between regions play a substantial role in helping grid operators balance supply and demand in all hours.

- Power flow analyses specific to the Western Interconnection demonstrate highly decarbonized systems can withstand selected typical contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies.

- An analysis of four extreme event stress cases in the Western Interconnection showed in some cases the buildout of additional interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of power shortages.

**The NTP Study identifies several examples of transmission investment that could be promising candidates for more in-depth consideration by planners and developers.**

- High Opportunity Transmission (HOT) interfaces represent transmission capacity expansion results between regions across many scenarios. Transmission projects that align with these HOT interfaces could be strong candidates for further study and serve as a starting point for accelerated transmission expansion.

- Transmission portfolios that deliver broad-scale benefits to consumers were developed using laboratory and industry tools. These transmission portfolios demonstrate new interregional transmission combined with intraregional transmission upgrades can help meet the flexibility requirements of high renewable energy power systems.

Regardless of future policy, market, and technology conditions…

**Grid planning at the national or multiregional scale requires enhanced institutional coordination, accessible data, and new grid modeling approaches, which have advanced under the NTP Study in partnership with technical and planning experts.**

- Advancing grid models—merging siloed planning processes, facilitating translations between models, and overcoming computational barriers—is critical to analyzing transmission comprehensively and capturing transmission's multifaceted impacts.

- Additional data on potential extreme events, technology advancements, and demand uncertainty will support robust transmission and reliability planning to identify the best expansion opportunities for consumers under changing conditions. Data access enables broader participation and collaboration.

- The identified benefits and expansion opportunities assume coordinated planning and use of transmission that goes beyond current practices. Developing guidelines for planners or a framework for coordination between numerous stakeholders can help realize these benefits.

# Introduction and Context

The NTP Study is a novel approach to national-scale, interregional transmission planning and carries with it significant insights for future transmission planning in the United States. The NTP Study links several long- and short-term power systems models to test numerous interregional and regional transmission buildout scenarios. These modeled scenarios and the resulting analyses test transmission options that are typically not considered in current planning practices and are coupled with a wide range of economic, reliability, and resilience indicators. The findings of the NTP Study will inform existing planning processes and have already contributed to additional development of transmission planning research and toolkits.

The U.S. transmission network is the backbone of the electricity system, serving 160 million customers as of 2022 and delivering highly reliable, affordable electricity that ensures the lights stay on and businesses operate, even during periods of extreme demand. Though the transmission system has served U.S. energy needs for more than a century, the country's needs are changing.

To meet the growing demand for electricity, improve electric service reliability and resilience, reduce consumer costs, and enable access to low-cost generation during both normal and emergency operations, there is growing recognition that additional interregional transmission capability and connectivity is necessary. However, existing grid planning efforts are fragmented and focused on identifying local and regional solutions. Current planning processes rarely consider whether interregional solutions could meet these needs more efficiently or effectively. Moreover, existing planning tools may not capture the value that interregional solutions can provide as the grid evolves in response to the rapid growth of advanced clean energy technologies, changing demand patterns driven by electrification and emerging industries, and the increased frequency of extreme weather events.

Though transmission owners and operators are investing in transmission system maintenance and upgrades, the rate of new transmission capacity added to the U.S. grid over the past decade is dramatically lower than in previous historical periods. In contrast, generation and storage capacity additions are steadily increasing. Over the past 5 years (2019–2023), nearly 200 gigawatts (GW) of new capacity has been added, about 80% of which is from clean electricity sources (wind, solar, storage, and nuclear) (EIA 2024). Continued interest in clean energy development is expected with more than 1,480 GW of solar and wind and 1,030 GW of storage seeking interconnection to the grid throughout the United States as of 2024 (LBNL 2024). Expanded transmission could enable additional opportunities for connecting and distributing already proposed generation projects, balance the variability of wind and solar resources, and accommodate growing energy demands while maintaining system reliability and energy affordability. An expanded transmission system will help meet national energy objectives—supporting domestic manufacturing, enabling increasingly energy-intensive computing, and electrifying large parts of the economy—and continue to serve the evolving energy needs of the next century.

These demands and opportunities are why, in 2022, GDO launched the NTP Study, a multiyear effort involving GDO and two national laboratories—National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL)—to understand the scope of interregional transmission needs and develop the national grid-scale planning tools and practices necessary to address these needs. The study team—comprising GDO staff and national laboratory (NREL and PNNL) researchers—has produced analyses and tools that have led to the development of additional interregional planning studies, reports, and papers. Together, the NTP Study and its companion reports seek to establish a foundation to identify and pursue interregional transmission solutions needed to meet national imperatives to enhance reliability, improve resilience to extreme weather and other disasters, and reduce consumer costs as the grid transitions to a decarbonized future.

# External Engagement

The NTP Study's external engagement efforts leveraged the expertise of a broad set of power system experts and interested parties around the country and provided opportunities for the study team to receive feedback on study assumptions, methods, and objectives. External engagement included the following four components:

- **Public** engagement through public meetings and an online comment form
- Engagement with **existing convener groups** such as the Eastern Interconnection Planning Collaborative and Western Electricity Coordinating Council
- A laboratory-led **Technical Review Committee (TRC)** inclusive of three subcommittees: a Modeling Subcommittee, a Government Subcommittee, and an Environmental Exclusion and Land Use Subcommittee
- **Tribal** outreach that included broad outreach to Tribes in the United States with assistance from DOE's Office of Indian Energy and targeted follow-up with interested Tribes.

During the project, DOE conducted 3 virtual public meetings, and the laboratory team conducted 18 virtual meetings with various subsets of the TRC, which included presenting interim results and gathering stakeholder feedback. More details on these meetings are presented in Chapter 1. In addition, TRC members individually provided feedback about scope and assumptions, shared modeling details about their regions, and helped clarify messaging regarding modeling results to be relevant for industry.

# Study Approach and Scenarios

The U.S. transmission system has a variety of technical challenges, many unique to each of the thousands of involved utilities, plus expansive geography with regional diversity in resources and planning outlooks. The transmission system is large and complex enough that modeling the true physics of the system at a fine level of detail over time pushes the limits of current computational capacity. To capture this complexity, the study team used several interlinked models—including translating

results from zonal models down to nodal resolution—to enable expansive insights about the future of the U.S. electricity system with the level of detail needed for rigorous transmission planning (Figure ES-1). The two key principles behind the study design are least-cost planning (i.e., planning for the lowest system cost portfolio from a broad array of options) and power system reliability (i.e., the ability of the power system to continually supply electricity). These principles are applied to a broad range of future power sector scenarios.

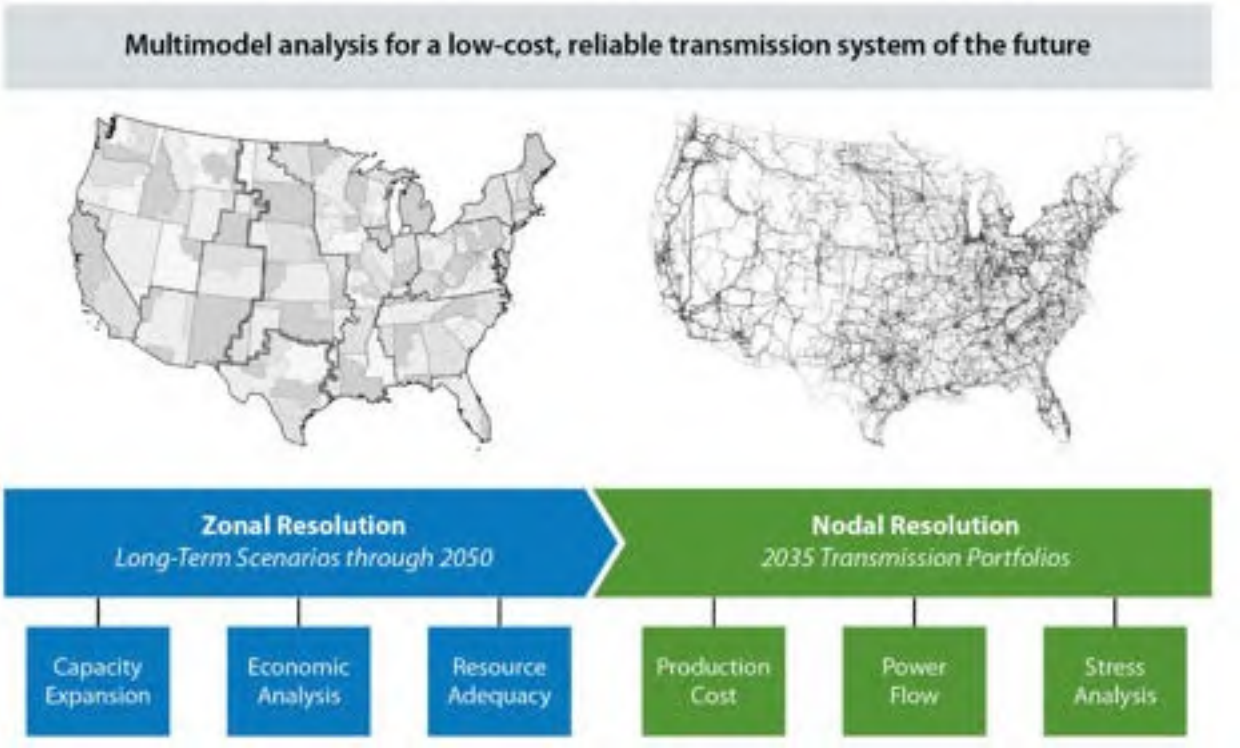


Figure ES-1. NTP Study approach

To analyze the future power system, the NTP Study first applies capacity expansion modeling and resource adequacy analyses of wide-ranging future electricity supply, demand, storage, and transmission needs for all regions across the contiguous United States. The study team analyzed numerous future scenarios through 2050 to examine uncertainties and identify robust regional and interregional transmission opportunities. The scenario analysis compared how the optimal electricity system—including generation, storage, and transmission—might evolve with different constraints and opportunities for transmission. The study team compared a “Limited” transmission framework, which constrains the annual rate of transmission expansion to the recent maximum rate and does not allow new interregional transmission builds, against three accelerated frameworks with increased options for transmission expansion (Figure ES-2). The comparison enabled isolation of the impacts of greater transmission expansion on power system costs, resource mixes, and emissions. Monetary cost and savings impacts are reported primarily for the U.S. electricity system as a whole with limited analysis on distributional impacts.

To better understand the challenges of applying transformative scenarios to detailed network models of the transmission system, the study team translated a subset of the scenarios into nodal representations of the system through a transmission planning phase. These nodal models—representing the entire contiguous U.S. transmission grid or the Western Interconnection in 2035, including scenario-specific transmission portfolios—were used to conduct production cost modeling and power flow analysis along with additional stress analysis. Conducting these analyses at the nodal resolution, consistent with industry practices, is necessary to further evaluate the engineering challenges of implementing transformative network topologies, operational differences between scenarios, and the reliability of the scenarios when integrating full network topologies and hourly operational constraints.

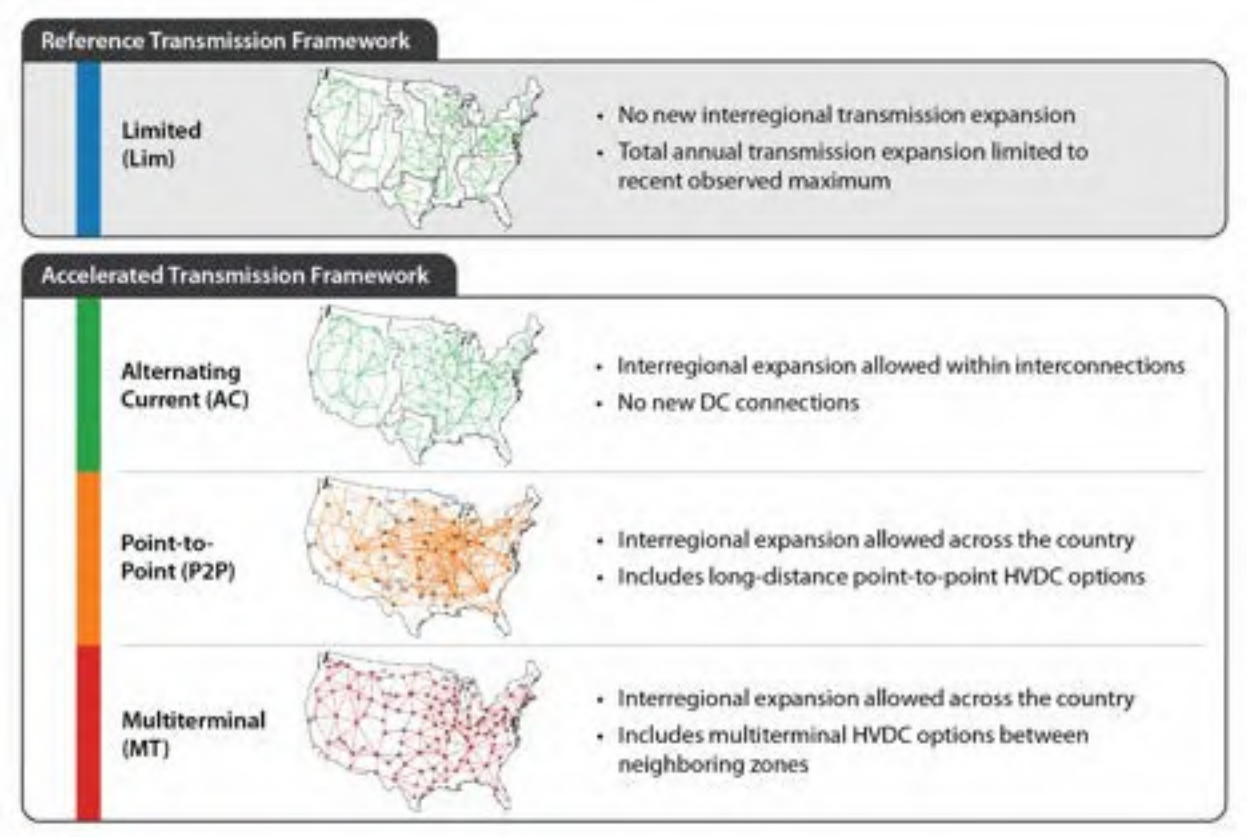


Figure ES-2. NTP Study transmission frameworks

Because the role and impact of transmission can vary based on many factors, the study team examined a wide range of demand growth and emissions reduction scenarios across the four transmission frameworks. The study includes current policy scenarios—which include state and federal policies enacted by June 2023, including the Inflation Reduction Act but excluding the final Clean Air Act section 111 standards—to examine how transmission development might impact future emissions. The study also includes scenarios with a limit on national annual emissions to achieve 90% power sector $CO_2$ emissions reductions (from 2005 levels) by 2035 and full grid decarbonization by 2045. The demand growth assumptions included a Low-Demand trajectory where U.S. load grows by 0.9% per year on a compound annual basis from 2021 to 2050 and Mid- and

High-Demand trajectories with greater load growth rates (2.0% per year and 2.7% per year, respectively) because of significant electrification projections. Under these latter two load growth cases, annual United States demand in 2050 is assumed to be 1.8–2.1 times demand in 2022, and demand peaks shift to winter periods in many regions. The analysis included multiple sensitivity cases to incorporate uncertainties with future transmission, generation, and storage costs; commercial availability of new low-emission options; renewable energy siting; impacts of climate change; and other factors. Altogether, the study team analyzed 96 scenarios. The study team made no judgment about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

# Key Takeaways: Deep Dive

The following provides further insight into the benefits of transmission, the grid transformation needed to realize these benefits, the implications of expanded transmission on system reliability, and new approaches that could facilitate future national-scale or multiregional transmission planning. These insights are presented with six principal findings and several related key takeaways for each finding. The first principal finding relates to current policy conditions, the next four are based on analysis assuming an emissions target is met, and the last finding is applicable under diverse conditions.

Under current policies…

### The lowest-cost U.S. electricity system portfolios that meet future demand growth and reliability requirements include substantial transmission expansion.

**The total transmission system of the contiguous United States expands to 2.1 to 2.6 times the size the 2020 system by 2050 and interregional transmission grows 1.9 to 3.5 times.** Figure ES-3 (left) shows total transmission capacity for all transmission frameworks under current policies. Transmission expansion found in the accelerated transmission expansion frameworks (alternating current [AC], point-to-point [P2P], and multiterminal [MT]) occurs to meet increasing electricity demand (2.0%/year under Mid-Demand) by enabling access to low-cost resources within regions and supports resource sharing between regions. The significant amount of transmission expansion is found to be cost-effective even in the absence of new emissions reductions policies. (Chapter 2)

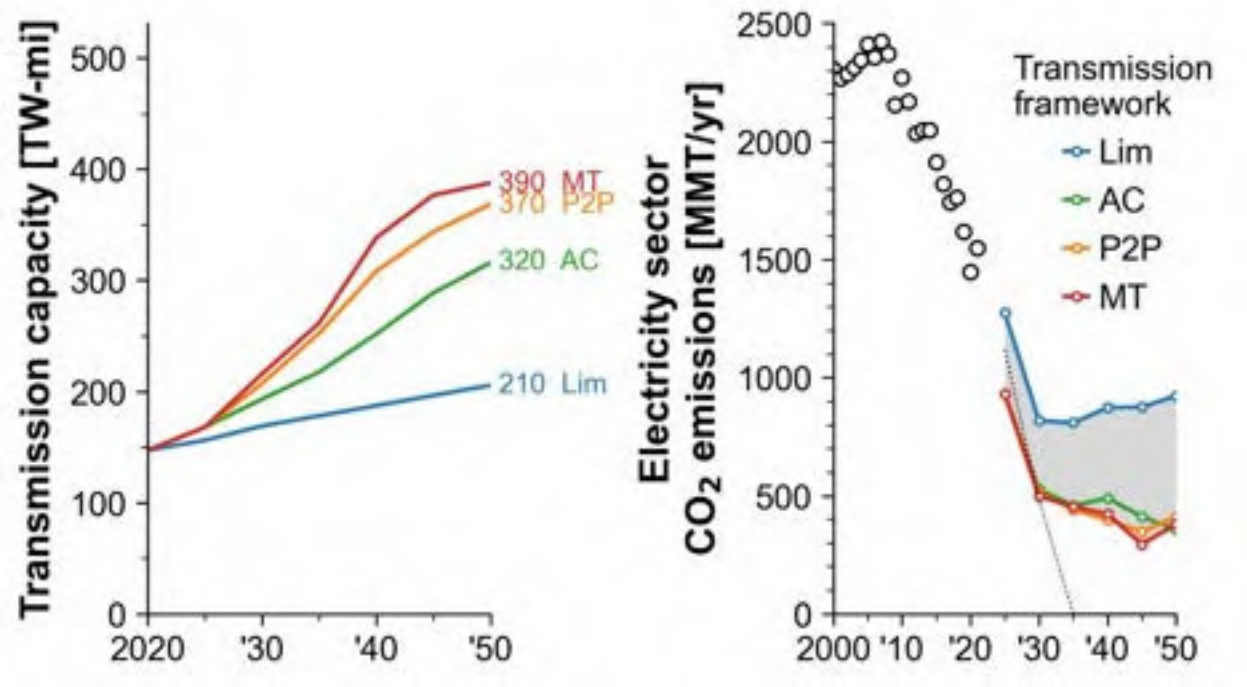


Figure ES-3. (Left) Total transmission expansion through 2050 and (right) annual national electric sector carbon dioxide emissions under current policies and Mid-Demand assumptions

**Interregional coordination to meet resource adequacy, using both existing and new transmission, can save the U.S. electricity system hundreds of billions of dollars.** Interregional transmission—over spatial scales larger than weather systems—enables efficient resource sharing between regions and smooths out variations in renewable energy availability. Leveraging new and existing transmission capacity across planning regions reduces the costs of meeting resource adequacy requirements. Under current policies, electricity system costs are reduced by about $100–300 billion with interregional resource adequacy sharing. (Chapter 2)

**Accelerating transmission deployment beyond historical rates reduces power system $CO_2$ emissions by 10 to 11 billion metric tons (43% to 48%) through 2050.** The scenario analysis finds increasing transmission greatly reduces electricity sector carbon emissions under existing policies. However, even with increased transmission expansion and recent state and federal clean energy policies, the power sector does not fully decarbonize without new policies. Figure ES-3 (right) shows annual electric sector emissions for all four transmission frameworks under Mid-Demand assumptions and with current policies as of June 2023. Compared to the Limited scenario, there is a roughly 56%–61% reduction in annual 2050 emissions in the three accelerated transmission frameworks and, on a cumulative basis (2025–2050), about 10–11 billion metric tons of $CO_2$ are avoided. The emissions reduction in the accelerated frameworks is driven by reduced reliance on fossil-fuel-based generation and capacity through greater deployment of wind and solar. (Chapter 2)

**The amount of transmission expansion and the emissions savings from transmission scale with the level of electricity demand.** Under high demand growth (2.7%/year), total transmission expands to 2.5 to 3.3 times the 2020 system by 2050. On a relative basis, growth in interregional transmission expansion is even greater with high demand; interregional transmission capacity in 2050 is up to 3.9 times the 2020 capacity in the MT framework. One driver of transmission expansion is from the increasing value of using interregional transmission for resource adequacy. With current policies only, cumulative avoided $CO_2$ emissions increase to 14 to 16 billion metric tons with high demand growth and are less substantial (3 to 4 billion metric tons) with low demand. (Chapter 2)

Under a U.S. electricity system carbon target that achieves a 90% greenhouse gas emissions reduction by 2035 and 100% by 2050…

## The study finds hundreds of billions of dollars of net benefits from large-scale transmission expansion compared to current transmission deployment.

**Accelerated transmission expansion leads to national electricity system cost savings of $270 to $490 billion through 2050.** Accelerating transmission expansion lowers costs for the contiguous U.S. electricity system in all low-carbon scenarios. Figure ES-4 shows total transmission expansion and system cost savings of accelerated transmission expansion frameworks compared to the Limited (Lim) framework in the central decarbonization scenarios (i.e., scenarios that achieve 90% emissions reductions by 2035 and 100% by 2045 with Mid-Demand growth). These savings account for net changes in all capital, operating, and fuel expenditures for generation, storage, and transmission from 2022 to 2050 on a present value basis. Through 2035, most savings are realized from avoided fuel costs, but in the longer time frame, savings are primarily achieved by a lesser need for capital investments. (Chapter 2)

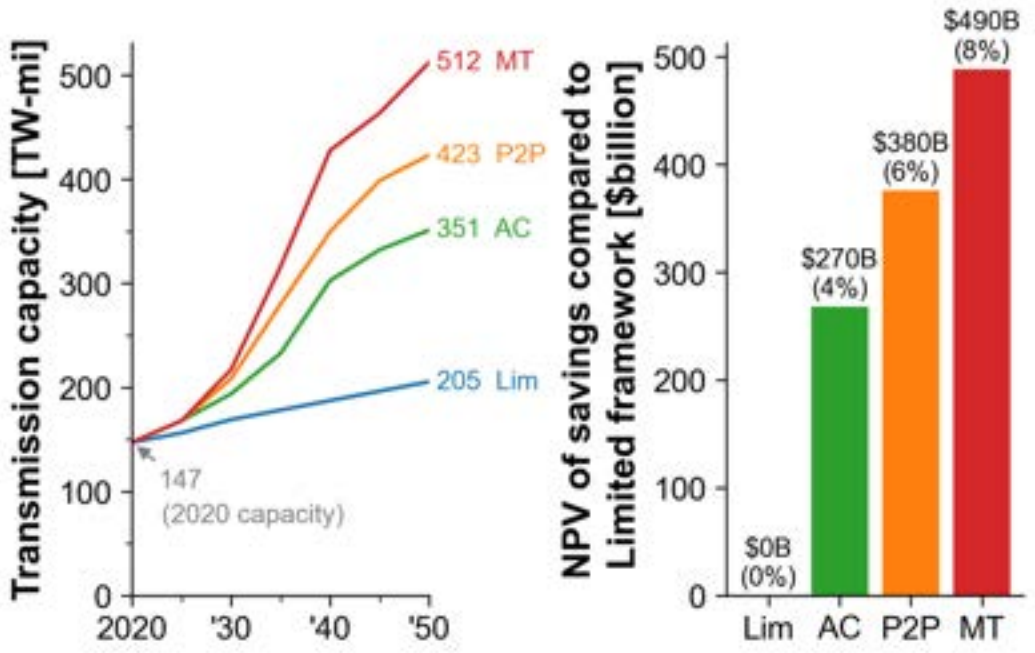


Figure ES-4. (Left) Total transmission expansion through 2050 and (right) cost savings of the accelerated transmission frameworks (AC, P2P, and MT) compared to the Limited framework with 90% by 2035 emissions reductions and Mid-Demand

*Net present values (NPVs) include fixed and operating costs of generation, storage, and transmission and federal tax credits from 2022 through 2050, discounted using a 1.7% real discount rate (OMB 2023). The parentheses above the bars show the percent savings compared to the total system costs of the Limited framework.*

**Incremental investments in transmission are more than compensated for by reduced electricity system costs for fuel, generation and storage capacity, and other costs. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission.** In the core scenarios, the benefit-to-cost ratio is 1.6 for the AC framework, 1.7 for P2P, and 1.8 for MT. These cost savings are achieved by enabling greater access to low-cost generation resources and expanding opportunities for resource sharing for reliability. Across all sensitivities and accelerated transmission frameworks, electricity system savings occur in all or nearly all regions of the contiguous United States. (Chapter 2)

**The benefits of transmission expansion to system costs scale with the level of electricity demand and rate of decarbonization.** Under high demand growth, estimated net savings from accelerated transmission range from $710–970 billion and coupling high demand with more rapid decarbonization can yield more than $1 trillion in savings. Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear power are unavailable. The economic benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many of them. (Chapter 2)

## A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits across a wide variety of scenarios.

**The U.S. transmission system expands to 2.4 to 3.5 times the size of the 2020 system by 2050 in scenarios that achieve 90% emissions reductions by 2035 with lowest power sector costs.** Figure ES-5 shows significant amounts of transmission are added to the grid to achieve 90% decarbonization of the electric sector in the contiguous United States by 2035 and 100% by 2045 while reliably meeting increasing demand. To achieve deep decarbonization, new transmission capacity rapidly scales and requires annual transmission installations multiple times the current development rate. With high demand growth, total U.S. transmission capacity in 2050 is 2.7–4.1 times the size of the 2020 grid. Many sensitivity cases result in even more extensive and rapid transmission expansion. (Chapter 2)

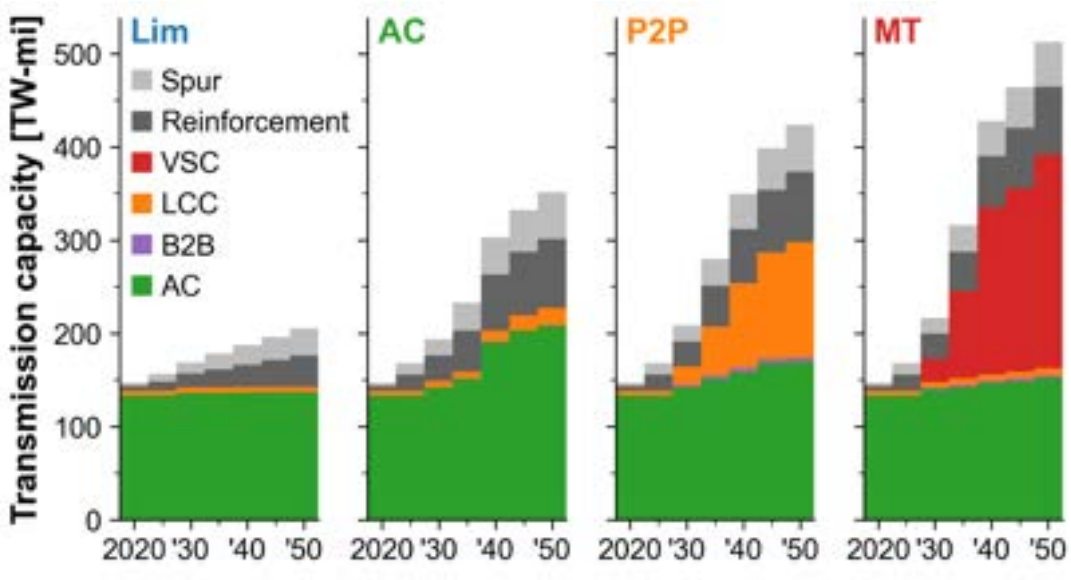


Figure ES-5. Total transmission capacity by type under Mid-Demand and 90% $CO_2$ reductions by 2035 assumptions for each transmission framework

*Spur and reinforcement refer to local transmission needed for wind and solar interconnection. Voltage source converter (VSC) and line-commutated converters (LCC) refer to HVDC technologies assumed with the former allowed in the MT framework and the latter under the P2P framework (and for existing DC lines). Back-to-back (B2B) refers to ties between separate interconnections. All other interzonal transmission is assumed to use alternating current (AC) transmission.*

**Transmission expansion occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country.** Local interconnection for new wind and solar (gray bars from Figure ES-5) is prioritized when transmission expansion is constrained (Limited framework), but both local and longer-distance transmission are installed under the least-cost portfolios without such constraints. With the accelerated transmission frameworks, new transmission infrastructure is installed throughout the contiguous United States, but long-distance transmission additions are particularly pronounced around the central wind belt. (Chapters 2, 3)

**The use of high-voltage direct current (HVDC) transmission technologies, including advanced MT converters, results in the greatest benefits to consumers across the transmission options studied.** For regional and interregional transmission, HVDC transmission additions outpace AC additions when allowed as shown for the P2P and MT frameworks from Figure ES-5. When translating zonal scenarios to nodal network models, HVDC was found useful for transferring power over long distances and between interconnections, but AC network expansion will continue to be the best solution for a large portion of transmission additions. Large interregional HVDC network solutions will also require additional strengthening of the regional AC networks they interconnect. (Chapters 2, 3)

**The largest benefits of transmission are realized when interregional transmission is most substantial, including when transmission is built across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6 to 4.6 times the 2020 capacity by 2050.** Figure ES-6 shows how interregional transmission—shown as the transfer capacity between the 11 planning regions—increases faster than peak demand growth for many regions in the accelerated transmission frameworks. With the assumed Mid-Demand load growth shown, the increase in *interregional* transfer capacity relative to 2020 is greater than the increase in *total* transmission estimated (2.6–4.6 times compared to 2.4–3.5 times). Interregional transfer capacities grow fastest for regions in the central part of the United States where future transfer capabilities are more than 100% of peak demand, especially with new HVDC options. When allowed, seam-crossing capacity expands significantly; more than ~40 GW of seam-crossing capacity is developed by 2035 across the three interconnection seams for the P2P and MT frameworks compared with about 2 GW today. (Chapters 2, 3)

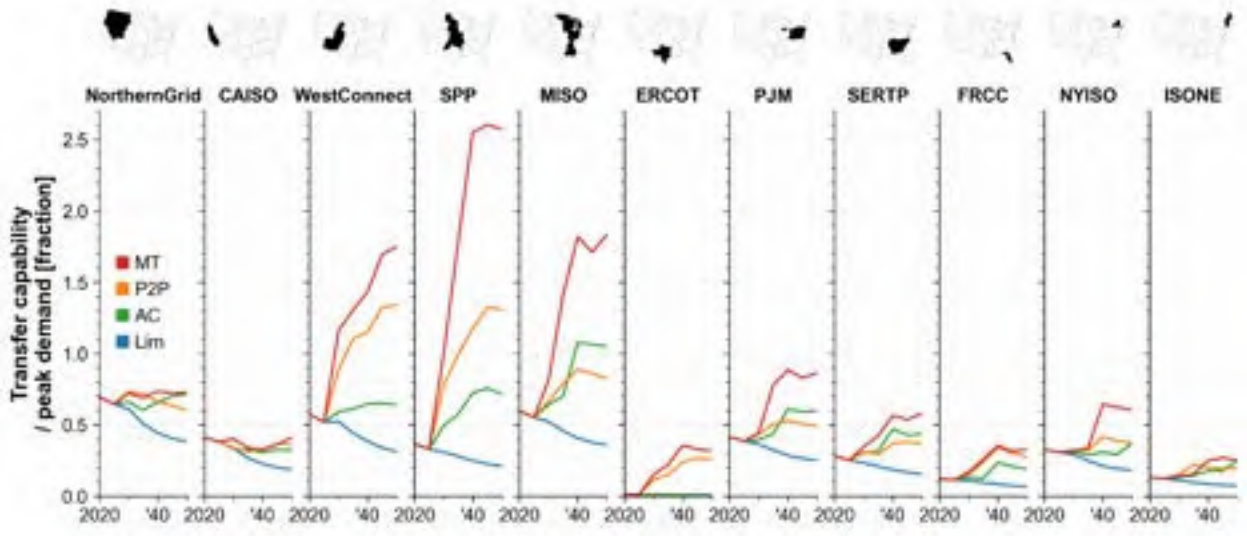


Figure ES-6. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

**Constraining transmission growth results in higher-cost portfolios with more nuclear generation, hydrogen, and carbon capture capacity required especially when carbon emissions are limited**. The economic benefits from transmission expansion result from increased access to the lowest-cost zero-carbon generation options: wind and solar. In the central decarbonization scenarios that achieve net zero emissions, combined wind and solar generation reaches about 80% of total generation by 2050, with hydropower and other renewable energy, nuclear, fossil carbon capture and sequestration, and hydrogen generation comprising the remainder. Generation shares of renewable energy in 2050 are about 20 percentage points lower in the Limited framework than in the other frameworks. Greater reliance on non-variable renewable energy (VRE) technologies when transmission (both local interconnection and longer-distance) is constrained results in higher system costs. (Chapter 2)

### Grid reliability can be maintained in future low-carbon grid scenarios with the lowest-cost solutions relying on coordinated transmission utilization between regions during periods of greatest stress.

**All 96 modeled future grids in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed resource adequacy standards.** Resource adequacy requirements ensure there are sufficient resources to meet demand considering expected availability and load uncertainties. Power systems are not planned for 100% reliability, but instead planning targets allow for a small amount of loss of load or demand that is not expected to be met. All systems modeled in the study are designed so the amount of unserved energy relative to total annual demand is less than 10 parts per million (ppm); this level of reliability is approximately equivalent to about 5 minutes per year of power disruptions for a typical customer. Using the central decarbonization assumptions and across all sensitivity cases and years, the median normalized expected unserved energy level is <1 ppm as estimated using 7 years of weather conditions. Current grid planners that use this resource adequacy metric apply a threshold ranging from 10 ppm to 30 ppm. (Chapter 2)

**When transmission regions coordinate to achieve resource adequacy, system costs through 2050 are lowered by $170–380 billion. In scenarios that allow coordination, transmission is used bidirectionally across many regional interfaces to support resource adequacy.** Coordinated planning to enable external resources to support local adequacy requirements increases the motivation for interregional transmission expansion. When resource adequacy requirements are met by in-region resources only, 40%–60% less interregional transmission capacity is added—resulting in the $170–380 billion higher systemwide costs. (Chapter 2, 3)

**High-resolution grid simulations demonstrate hourly demand and supply can be balanced in power systems with very high shares of renewable energy. In scenarios with larger transmission expansion, imports and exports between regions play a substantial role in helping grid operators balance supply and demand in all hours.** Interregional transmission provides significant opportunities and challenges for grid operators. In scenarios with more interregional transmission, the relative amount of demand that may be met by imports or the amount of power that will be exported from a region increases, highlighting coordination in planning and operations between regions may need to increase. Figure ES-7 shows the net interchange of power relative to demand from hourly production cost simulations for three power systems in 2035 that achieve 90% emissions reductions. Most regions rely on imports or exports in all three scenarios, but across almost all regions, the accelerated transmission scenarios lead to more overall energy exchange. More specifically, 19% of the total energy consumed in the Limited scenario flows over interregional transmission lines; that number increases to 28% in AC and 30% in the MT-HVDC scenario. In addition, most regions maintain their role as either primarily importers or primarily exporters across all three scenarios, but the amount of power being exported in the accelerated frameworks is often much greater than the load of a region (>1.0 in Figure ES-7) in Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and WestConnect. (Chapter 3)

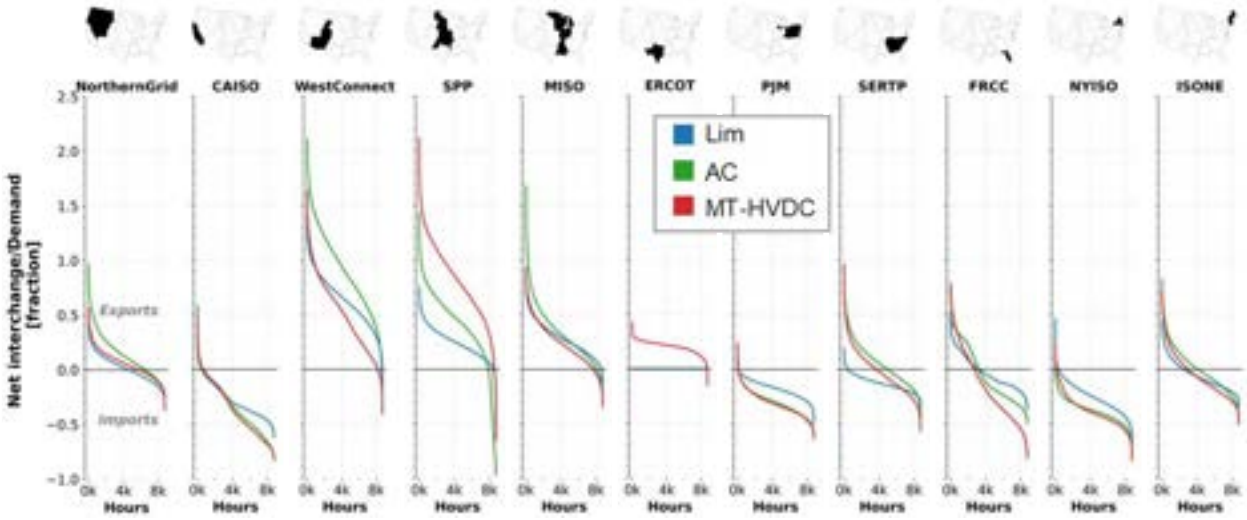


Figure ES-7. Ratio of net interchange to demand for the 11 planning regions across all hours in a year (ordered from highest to lowest) for Mid-Demand 90% emissions reductions by 2035 systems

*Positive values indicate net exports and negative values indicate net imports. The MT-HVDC scenario refers to the nodal 2035 translation of the MT scenario, which encompasses characteristics of both HVDC scenarios from the zonal scenarios.*

**Power flow analyses specific to the Western Interconnection demonstrate highly decarbonized systems can withstand selected typical contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies.** Power flow analyses test whether voltages can remain within safe ranges even during major contingencies, such as individual transmission line or large generator outages. A power flow analysis of a future 90% decarbonized Western Interconnection that is generating 70% of energy from wind and solar demonstrates new transmission lines can help avoid voltage or thermal loading risks to the system, even when they are highly loaded. Figure ES-8 demonstrates no significant changes in voltage occur because of a modeled contingency. Voltages are stable in several scenarios and selected contingencies, including outages on new, large, highly loaded transmission lines. This is a preliminary indication of their robustness and indicates transmission portfolios modeled do not represent a significant risk to the system, even when highly loaded. Multiple resources help maintain stable voltages and frequencies in these transformative futures. Utility-scale energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies. (Chapter 4)

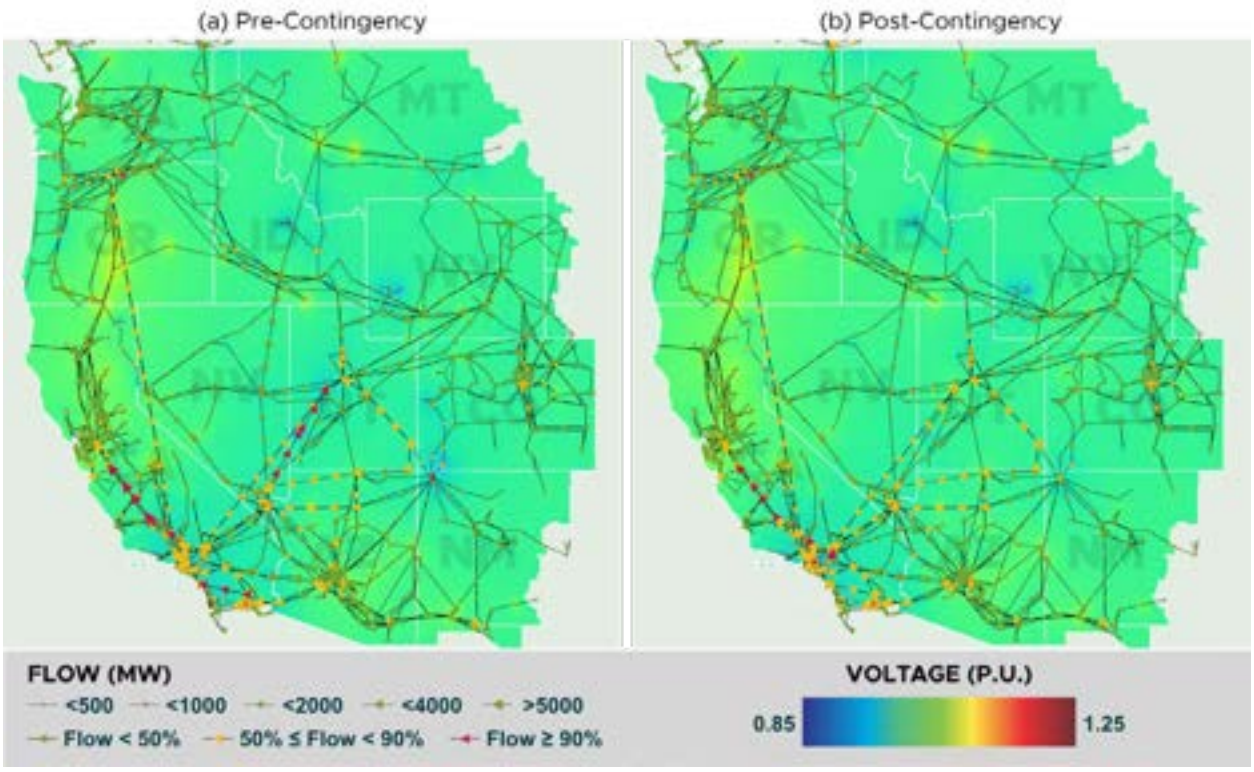


Figure ES-8. Voltage heatmaps (a) pre- and (b) post-contingency for the loss of 2600 megawatts (MW) of generation at a nuclear power plant for the AC scenario: No significant voltage changes following the contingency

*Per-unit (P.U.) voltage is the actual (measured) voltage divided by the base voltage, or rating, of the transmission component.*

**The buildout of additional interregional transmission can support the power system during certain types of extreme weather events, decreasing the potential for and amounts of power shortages. More work is needed in this area.** The study team conducted a stress analysis to evaluate the impacts of extreme events on future Western Interconnection power systems with greater and lesser transmission expansion. Extreme high-demand events considered included historic heatwaves (which are worsened to 2035 conditions to reflect the expectation of a warmer climate scenario) and drought conditions to project a potential reduction in hydropower generation. These events were also combined into a multi-event threat representing a co-occurrence of a drought (reduced hydropower) alongside a heatwave (increased energy demand) to test grid operations—including use of transmission—under compounded extreme conditions. Though these are not the only future stress cases that could occur, they serve as a proxy for understanding the system's response under stress.

To assess the role of transmission during extreme events, the study compares the Limited to the AC frameworks, as seen in Figure ES-9 and Figure ES-10. When a California or Pacific Northwest heatwave is combined with hydropower droughts in the Pacific Northwest, the unserved energy significantly increases for both regions. These increases are lower in the AC framework compared to the Limited framework in six of the eight scenarios considered, demonstrating how transmission could help improve reliability during high stress periods. For the remaining two scenarios, the study team observed lower amounts of unserved energy in California in the Limited framework compared to the AC framework. This is because the Limited framework has greater installed capacity of local dispatchable resources (such as battery storage and natural gas) that could support the state's increased load demands amid decreased generation imports from the Pacific Northwest. This result indicates transmission and resource planners should carefully consider interregional transmission capacity and all types of transmission, generation, and storage resources—including local assets—when minimizing the risks of extreme stress events.

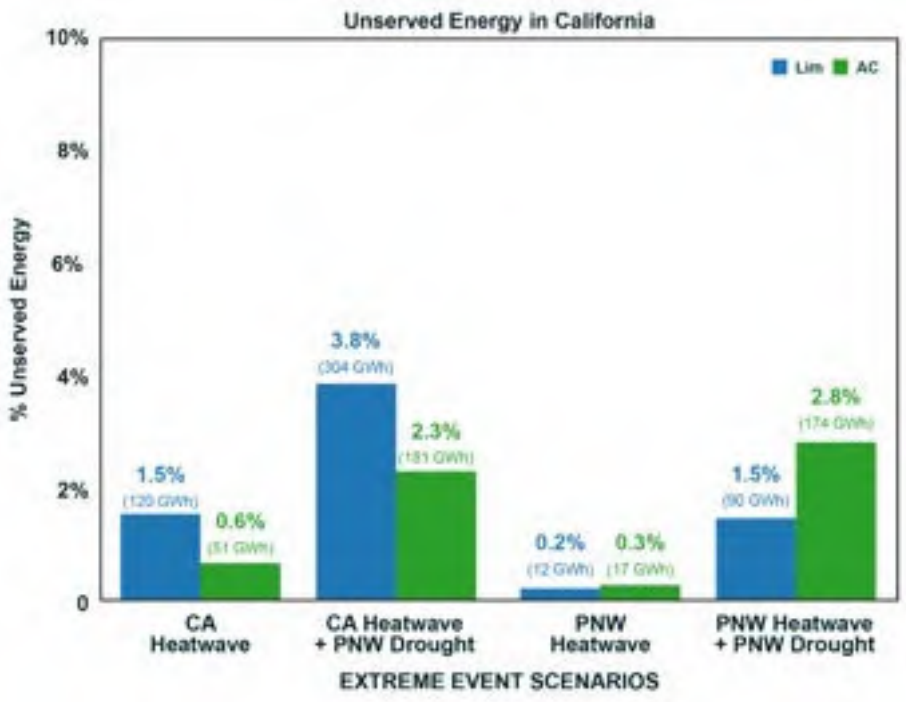


Figure ES-9. Projected unserved energy in California in response to singular and combined extreme events for the Limited and AC transmission frameworks

*GWh = gigawatt-hours; CA = California; PNW = Pacific Northwest*

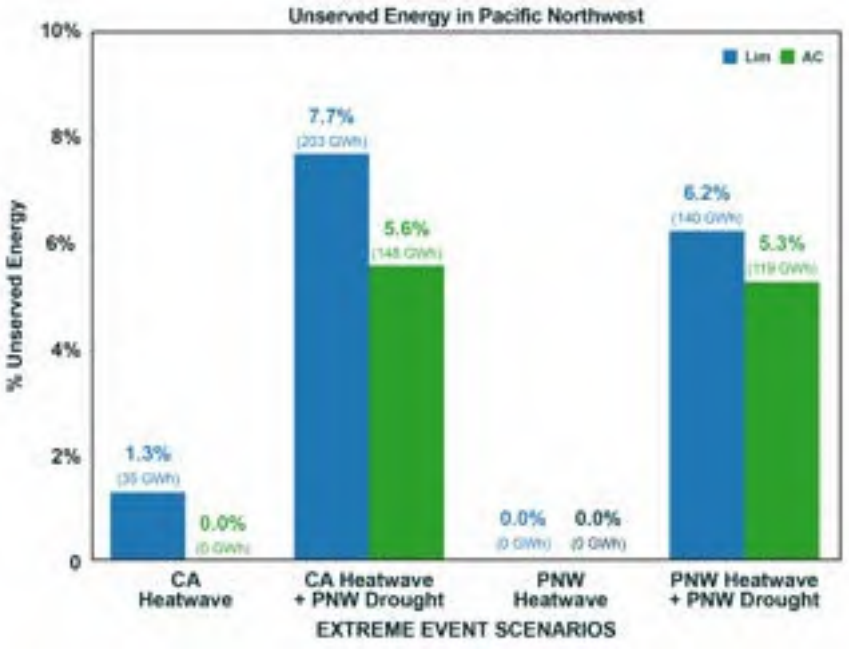


Figure ES-10. Projected unserved energy in the Pacific Northwest in response to singular and combined extreme events for the Limited and AC transmission frameworks

*GWh = gigawatt-hours, CA = California, PNW = Pacific Northwest*

The economic value of lost load for the unserved energy periods described here was in the tens to hundreds of billions of dollars for individual regions (i.e., the Pacific Northwest or California). However, to accurately assess the resilience benefits of interregional transmission, the probability of the extreme events must be incorporated into a full economic evaluation. Future work should include more types of extreme events across broader geographic areas. (Chapter 5)

### The NTP Study identifies several examples of transmission that could be promising candidates for more in-depth consideration by planners and developers.

**High Opportunity Transmission (HOT) interfaces represent transmission capacity expansion results between regions across many scenarios. Transmission projects that align with these HOT interfaces could be strong candidates for further study and serve as a starting point for accelerated transmission expansion.** Spatial patterns of new transmission are similar across diverse conditions, and a systematic evaluation of interregional expansions can reveal HOT interfaces. Capacity for each HOT interface is defined as the expansion between subregions that occurs in 75% of the sensitivity cases (with 90% emissions reductions and Mid-Demand assumptions) by 2035. Figure ES-11 shows the HOT interfaces. (Chapter 2)

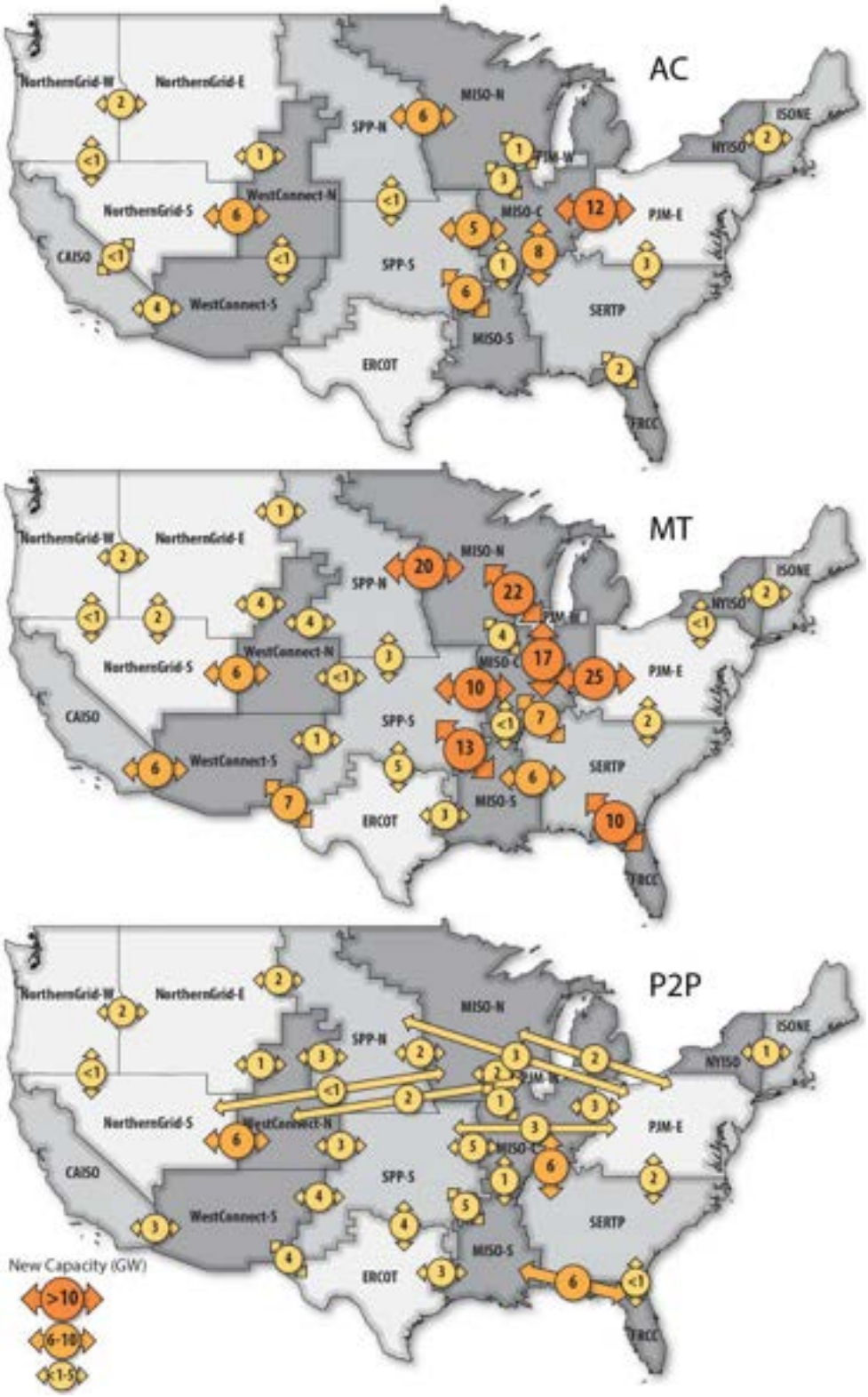


Figure ES-11. HOT interfaces for the 90% by 2035, Mid-Demand scenario, for the AC (top), MT (middle), and P2P (bottom) frameworks

**Transmission portfolios that deliver broad-scale benefits to consumers were developed using laboratory and industry tools. These transmission portfolios demonstrate new interregional transmission combined with intraregional transmission upgrades can help meet the flexibility requirements of high renewable energy power systems.** Translating zonal capacity expansion modeling results to nodal transmission portfolios is a key part of this study. Such a translation enables more detailed evaluations of the modeled scenarios, which establishes greater confidence in the operational reliability of the transformative future power grids envisioned. Figure ES-12 shows the transmission portfolio for the AC (top) and MT-HVDC (bottom) frameworks for 2035. The implementation of the AC scenario results in significant expansions of 345- and 500-kilovolt (kV) lines that help collect low-cost renewable energy in concentrated areas and deliver power over long distances. The MT-HVDC scenario uses MT HVDC for long-distance power transfers but still relies heavily on the expansion of the AC network to move power within and between regions. The MT-HVDC scenario also enables connections between the three interconnections, increasing the existing (as of 2023) amount of transfer capacity between the interconnections by greater than 20 times. The transmission portfolios from Figure ES-12 are only two specific illustrative implementations of the zonal HOT results. They provide a possible starting point for national or multiregional transmission planning that could deliver the cost, reliability, and emissions benefits found in the study. The transmission portfolios identified in this study can also be a starting point for states interested in exploring multistate and interregional transmission options. They do not represent proposed routes or other siting considerations. (Chapter 3)

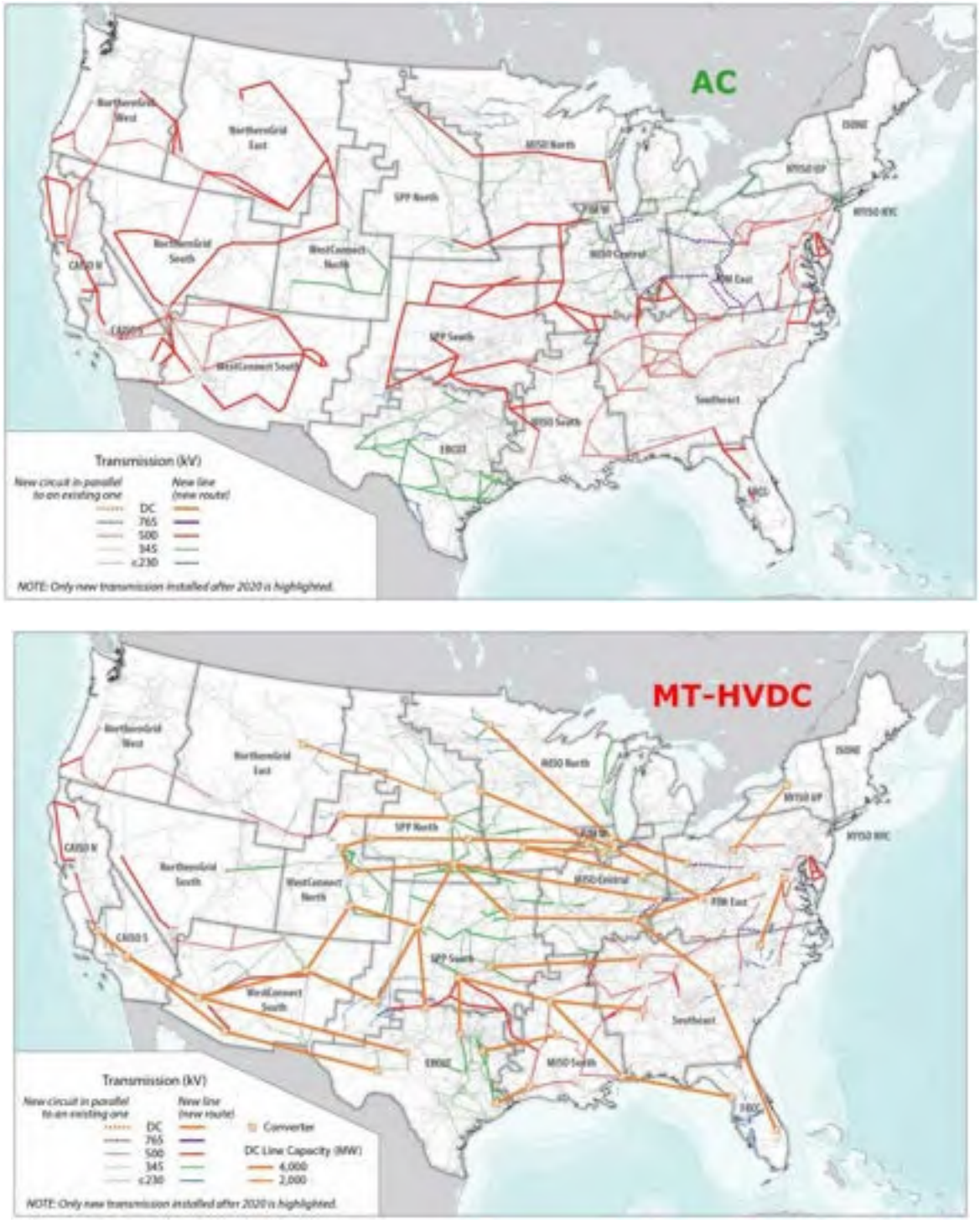


Figure ES-12. Transmission portfolios for the 90% by 2035 Mid-Demand scenario for the AC (top) and MT-HVDC (bottom) transmission frameworks

*Only new transmission (developed between 2020 and 2035) is shown with the colored lines on the map. The gray lines in the background represent the existing network.*

Regardless of future policy, market, and technology conditions…

**Grid planning at the national or multiregional scale requires enhanced institutional coordination, accessible data, and new grid modeling approaches, which have advanced under the NTP Study in partnership with technical and planning experts.**

**Advancing grid models—merging siloed planning processes, facilitating translations between models, and overcoming computational barriers—is critical to analyzing transmission comprehensively and capturing transmission's multifaceted impacts and potential benefits.** In this study, new approaches were developed that can be useful to industry going forward. For example, this study took current industry-grade production cost models and converted them to industry-grade power flow models that were stable enough to use for detailed reliability analysis. The study team used a tool called C-PAGE that is available for industry to convert the production cost modeling results into power flow models for the future model year. An intelligent sampling method was developed for selecting representative hours from a production cost model to use for power flow analysis, recognizing the impacts of significant variations in load, wind, solar, and online generation mixes. The developed tools enable the extraction of power flow cases from production cost model simulations, regardless of generation mix, which can be used for more in-depth reliability studies. The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies. The study's advanced data analytics can shed light on grid behavior for several AC power flows, providing hourly snapshots and scenarios that the industry may use to examine new transmission investments. The study team also integrated resource adequacy and capacity planning tools to better guide investments to more efficiently address future grid stress conditions. Methods to simulate the impacts of climate change and incorporate them into grid models were also advanced from the study and applied in the analysis. (Chapters 2, 3, 4, 5)

**Additional data on potential extreme events, technology advancements, and demand uncertainty will support robust transmission and reliability planning to identify the best expansion opportunities for consumers under changing conditions. Data access enables broader participation and collaboration.** The extreme event analysis presented here considered only droughts and heat waves in the western United States. Analyses of different types of extreme events, including cold snaps at locations throughout the United States, will support understanding the full potential resilience benefits of transmission options. More work is needed to properly characterize these events to ensure planning efforts can appropriately identify and size infrastructure, including transmission, to maintain reliability in the face of changing risks. Likewise, other data on technology advancements and demand uncertainly will be equally important. Data availability and access are critical to developing solutions that fit regional and national needs. (Chapters 2, 3, 4, 5)

**The identified benefits and expansion opportunities assume coordinated planning and utilization of transmission that goes beyond current practices. Developing guidelines for planners or a framework for coordination between numerous stakeholders could help realize these benefits.** Potential benefits of transmission include avoided capital costs, reduced operating costs, increased reliability, and increased resiliency. Many of the scenarios from the NTP Study—particularly the accelerated transmission framework scenarios—assume these benefits could be captured from interregional transmission. But in reality, these benefits may be difficult to fully capture unless action is taken to reduce existing barriers to achieving coordinated planning and utilization of interregional transmission. Of particular importance, as demonstrated from the results of the NTP Study, is increasing opportunities for resource adequacy sharing between regions. A companion report to this study (Simeone and Rose 2024) explores potential solutions to help better integrate resource adequacy sharing into planning time frames. (Chapters 2, 3, 4, 5)

# Future Work

The NTP Study addresses a wide range of questions about the role of transmission in the bulk power system in the contiguous United States, along with the reliability and cost benefits that can be gained through accelerated transmission expansion. However, a national-scale, interregional transmission planning effort of this scope is a significant undertaking, and there are several questions that either lie outside the scope of this analysis or require further investigation. GDO intends to continue to lead national-scale grid planning efforts by developing enhanced institutional coordination, accessible data, and new grid modeling approaches in partnership with technical and planning experts. GDO also intends to work with industry to put the findings and tools developed in the NTP Study into action in ongoing planning processes at the state, regional, and interregional levels. Future work could include the following:

- **Transmission siting.** Transmission network data available for the NTP Study are limited in that detailed rights-of-way information and other transmission infrastructure details (age of conductors, tower type, and so on) that could lead to more refined solutions for transmission expansion are not readily available. Additional analysis on the location and routing of transmission—and integration back into planning models—will build confidence in potential transmission solutions. Though not a focus of this study, future in-depth consideration of promising transmission options should include careful consideration of environmental, health, and community impacts and options.
- **Reliability and resilience.** The NTP Study team analyzed several aspects of reliability and resilience, including resource adequacy, contingency analysis, stress analysis, and system flexibility required for reliable operations. These elements of reliability should be further studied—particularly analysis of reactive power coordination, dynamic simulations and frequency response, and voltage ride-through during grid disturbances. In addition, though the NTP Study was able to evaluate discrete extreme weather events for the Western Interconnection, additional events should be studied to understand the role of transmission in

mitigating risks from extreme weather. Future analysis should consider different areas of the country, including across multiple interconnections, and different types of singular and compounded extreme events.

- **Markets and operations.** The NTP Study nodal scenarios envisioned complete coordination between transmission regions in the system's operations. As highlighted by a companion report for the NTP Study, *Barriers and Opportunities To Realize the System Value of Interregional Transmission* (Simeone and Rose 2024), complete coordination is optimistic given the challenges with coordinating the use of existing interregional transmission. These challenges will likely be magnified if the amount of interregional transmission is substantially greater than it is today. Further work should take a closer look at how different levels of market and nonmarket and operational coordination can impact transmission's use and value.
- **Distribution of impacts.** The NTP Study included limited analysis of regional disaggregation of cost savings from accelerated transmission and relative impacts between producers and consumers. The analysis of costs and savings described in this report primarily applies to the contiguous U.S. electricity system as a whole. Additional analysis is needed to assess who would gain the most benefits and who might incur greater costs. Expanding the distributional impacts assessment between the diverse producers and consumers, such as between different socio-economic classes and between generators and transmission, could better inform impacts of transmission expansion to individual households, equity and energy justice issues, and market design and cost recovery to incentive new infrastructure development. Furthermore, expanding the impacts beyond costs and greenhouse gas emissions would provide a more comprehensive evaluation of transmission expansion.
- **Enabling technologies.** The NTP Study considered several transmission technologies and used advanced methods to capture multiple value streams for transmission. However, additional considerations about the best technology to increase capacity between regions, such as reconductoring or the use of grid-enhancing technologies (e.g., dynamic line ratings and power flow control devices), were not studied in detail. Because many transmission additions in the coming decades are likely to include a combination of new transmission and grid-enhancing technologies, better capturing these trade-offs could be an important step in planning studies going forward. In addition, the experience with HVDC technologies in the United States is limited, so opportunities exist to better integrate HVDC technology capabilities into system planning and operations.
- **Grid edge solutions.** The NTP Study did not explore all alternatives to transmission, including distributed resources and nonwires solutions. Energy efficiency, demand response, coordinated electric vehicle charging, virtual power plants, and other demand-side flexibility programs can play important roles in the energy transition. They can reduce the need for transmission and supply-side resources by reducing electricity demand, avoid the need for assets with low utilization, and help support resource adequacy and reliability. However, the scale

of transformation in the NTP Study scenarios—especially the high-demand or decarbonization scenarios—will likely still require large-scale transmission expansion even with the implementation of these nonwires solutions. These solutions may have large impacts on certain regional needs, and further study can improve estimates of these needs.

- **Supply chains.** The NTP Study did not explore the availability of materials and infrastructure to meet the transmission and generation needs in the scenarios. Further study of the supply chains of critical infrastructure is important—particularly HVDC technologies.
- **Policy options and coordination.** The NTP Study included binding state policies in the modeled scenarios and invited TRC Government Subcommittee members and other state policymakers and experts to provide comments on the policy representations and assumptions. Future modeling work should further explore options to achieve emerging federal and state policy goals and targets. Future DOE modeling and analysis activities should include convenings and data to support regional and interregional coordination efforts.

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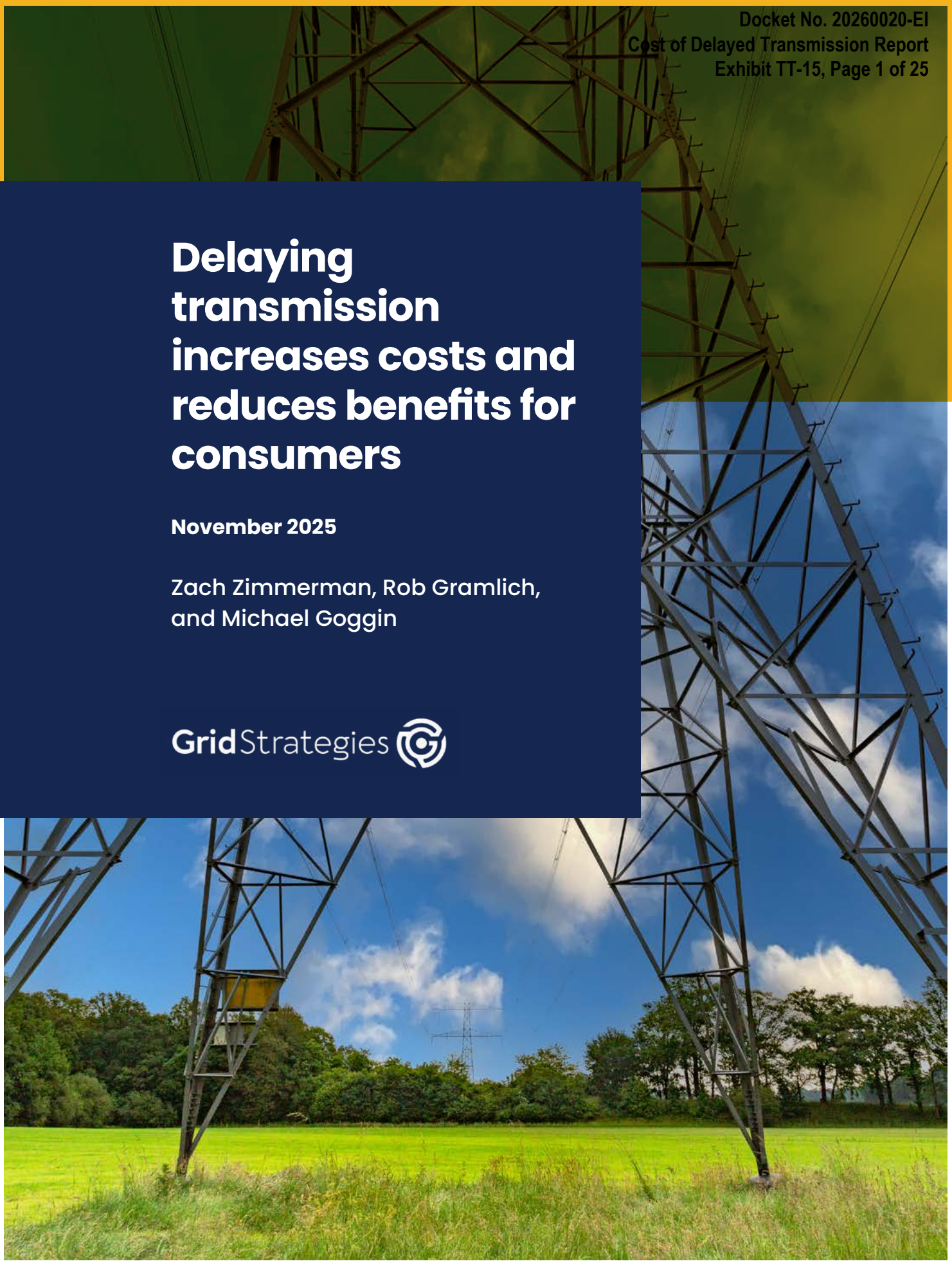
DOE/GO-102024-6190 | October 2024

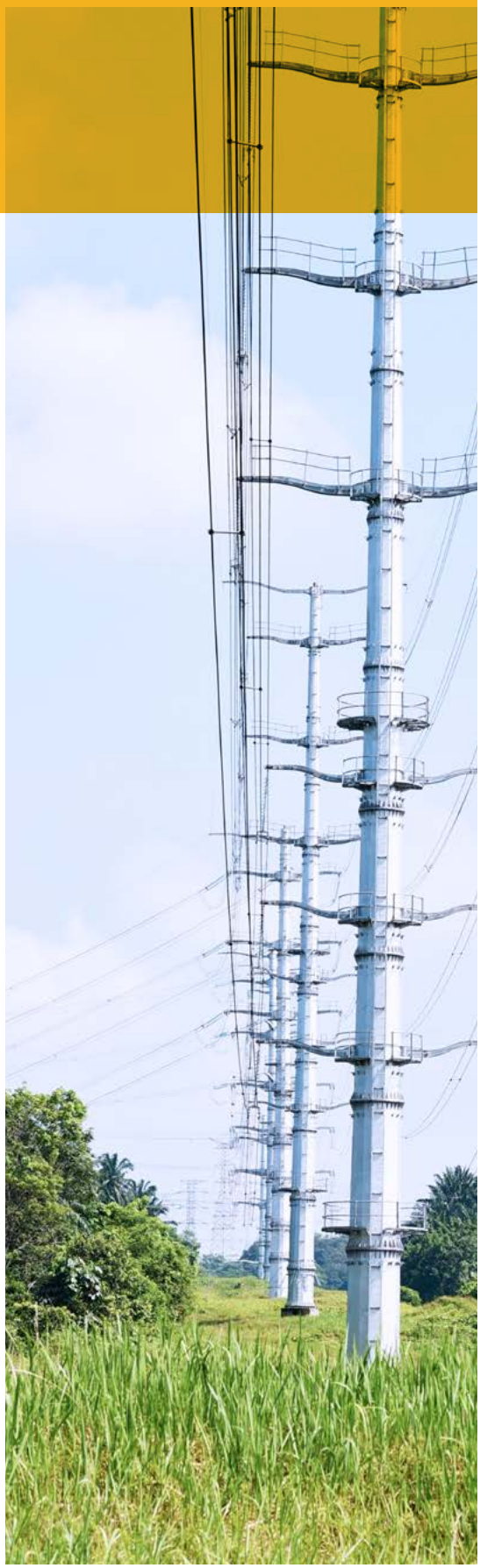


# Delaying transmission increases costs and reduces benefits for consumers

**November 2025**

Zach Zimmerman, Rob Gramlich, and Michael Goggin

Grid Strategies



# EXECUTIVE SUMMARY

The electric grid supports nearly all of our modern economy and day-to-day American life. Insufficient expansion and modernization of the electric grid to meet the growing needs of Americans' homes and businesses, as well as delays in development of new grid capacity, not only holds back economic growth but also costs consumers money.

Many studies have demonstrated the significant societal benefits stemming from development of electric transmission infrastructure, including economic and reliability benefits. By providing access to lower-cost sources of electricity and reducing costly congestion, transmission reduces electricity production costs. This benefit extends to leveraging regional and interregional diversity of supply portfolios and demand patterns. Furthermore, a robust transmission system facilitates reliable and resilient power delivery without costly service interruptions. In turn, a more reliable and resilient power system benefits national economic and technological competitiveness (i.e., dominance in artificial intelligence), economic growth, and job creation.

Developing transmission infrastructure entails complexity in the engineering, financing, planning, construction, operations, and cost recovery of transmission—the entire development cycle. Challenges are exacerbated by the number of interested entities, including federal, state, and local authorities with sometimes overlapping jurisdiction and the many other stakeholders that have an interest in the process or outcomes of linear infrastructure development. The result is that there are numerous opportunities for delay.

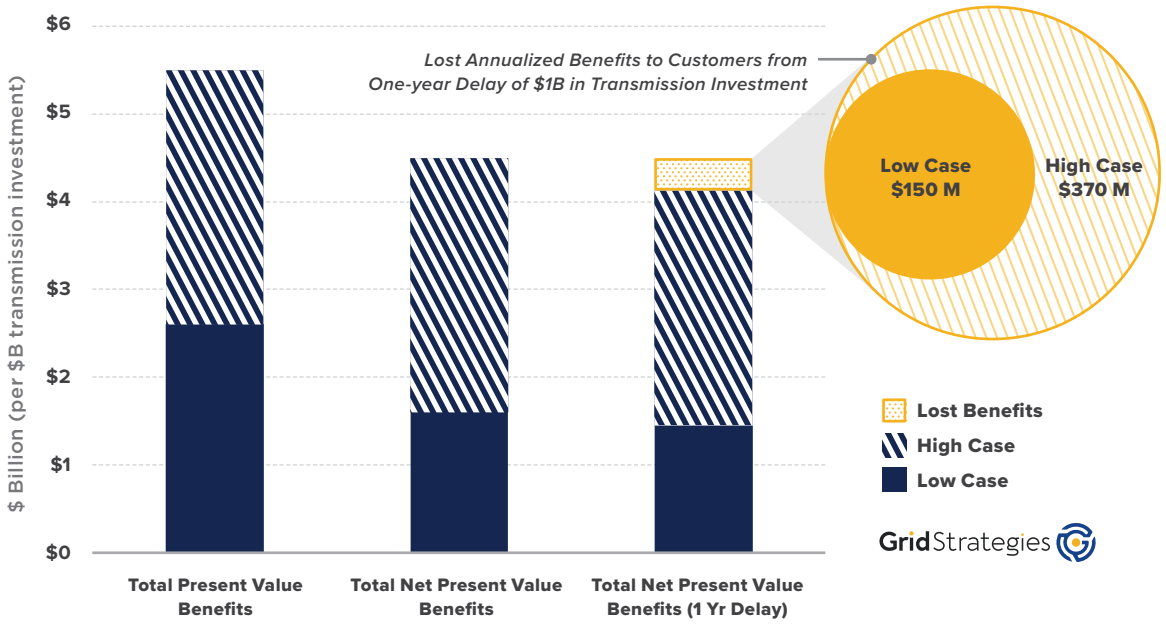
This report takes one approach to quantify how delays in developing transmission impose costs

on consumers by postponing or forfeiting benefits. For the report, we review eight benefit-cost studies for transmission portfolios across the country. Using each study's reported total benefits, we convert those benefits to an annualized value and estimate the cost of a one-year delay in foregone benefits. The report is focused only on the economic and reliability costs of delaying transmission to consumers and is not intended to catalog all causes of delay, assess specific project timelines, or offer policy prescriptions.

**We find that for every $1 billion investment in well-planned, large-scale transmission that is delayed, it costs consumers approximately $150 million to $370 million in lost net benefits for each year of delay, while also impeding job creation, slowing economic growth, and impacting national security.**

Furthermore, our review of economic impact studies finds that each $1 billion of delayed transmission investment defers an estimated 11,000 to 25,000 direct, indirect, and induced job-years. The additional transmission capacity available as a result of the investment also allows businesses to grow, such as new data centers or new or expanded manufacturing facilities, which provide additional jobs and economic growth.

**FIGURE ES-1** | Benefits lost from delaying transmission one year (per $Billion invested)




Consumers benefit most when transmission projects are energized as soon as possible. Our estimates represent real losses in benefits to consumers, including through lower fuel and capacity costs and improved power system reliability—explored further in the first section of this report. Because many of these benefits come from more efficient operation of the system, they are not just pushed into the future but rather are lost forever if the transmission projects are not placed in service as planned. In addition, the time value of money means delays to infrastructure development also forfeit the highest-value near-term savings. In other words, the affordability of electricity supply depends in no small part on timely execution of efficient and cost-effective transmission expansion.

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# INTRODUCTION

Transmission capacity of the nation's vast, complex power network needs to expand to meet significant current and forecasted growth in electricity demand. This level of development is necessary to ensure reliability, resilience, facilitate energy trade in advancement of efficiency and affordability of the power system, and, significantly, to support US competitiveness in the information technology and artificial intelligence space by supporting energy-intensive data center expansion.

Over the last 20 years, the power industry has been operating under conditions of limited electricity demand growth, with a transmission grid that required only limited expansion to ensure reliable service to meet that demand. However, utilities across the country are now seeing significant jumps in load forecasts. In a recent Grid Strategies analysis, we concluded that expected load growth has increased fivefold from the 2022 to the 2024 forecast. In 2029, less than 5 years from now, that analysis shows total peak demand growing by 15%.[1]

The sudden shift from flat electricity demand into a mode of rapid growth has led to growing consensus around the need for new large-scale transmission investment. In the Federal Energy Regulatory Commission (FERC)'s 2024 State of the Market Report, the agency reported that nearly 1,000 miles of new transmission placed into service over the last year was driven by load growth, making it the second-largest driver of new transmission projects after reliability needs.[2] This is an increase in the miles of load-growth-driven transmission that came online in 2023 and

1 J. Wilson, *et al.*, Grid Strategies LLC, *Strategic Industries Surging – Driving US Power Demand*, at 3 (Dec. 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

2 Federal Energy Regulatory Commission (FERC), *2024 State of the Markets*, at 32-34 (Mar. 2025), https://www.ferc.gov/media/state-markets-report-2024.

2022.[3] Some regional grid operators have already noted that their transmission system has or will reach capacity soon due to load growth.[4] This trend is also developing in large customer service areas served by vertically integrated utilities with larger footprints, that in some instances serve greater loads than some regional grid operators.

Recognizing that the existing transmission network is strained under current demand levels and significant expansion is required, national identification of large-scale planned transmission is on the rise. New transmission projects tied to rising electricity demand, along with North American Electric Reliability Corporation (NERC)'s 2024 Long-Term Reliability Assessment (LTRA), show a significant increase in planned transmission miles over the past year, both for regional grid operators and for large integrated utility footprints witnessing similar load growth. The 2024 LRTA reports there are 28,275 miles of transmission (>100 kV) planned or under construction through 2034. This estimate is almost 10,000 miles higher than the 2023 LTRA 10-year projections and is well above the average of 18,900 miles over the past five years of NERC's LTRA reporting.[5]

Given the clear need for large-scale transmission expansion, it is critical to understand the impacts if infrastructure expansion is not achieved on a timely basis. This report covers key economic and reliability benefits of transmission. The report then draws on eight separate benefit-cost analyses from around the country to estimate the costs of these delays to consumers.

3 FERC, *2023 State of the Markets,* at 42-44 (Mar. 2024), https://www.ferc.gov/media/2023-state-markets-report; FERC, *2022 State of the Markets,* at 27-29 (Mar. 2023), https://www.ferc.gov/media/report-2022-state-market.

4 J. Wilson & Z. Zimmerman, Grid Strategies LLC, *The Era of Flat Power Demand is Over*, at 20, (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

5 North American Electric Reliability Corporation (NERC), *2024 Long-Term Reliability Assessment,* at 34 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

# BENEFITS OF TRANSMISSION TO CONSUMERS AND SOCIETY

Investment in transmission provides numerous direct and indirect benefits to consumers. These benefits include resource adequacy value and economic benefits through the aggregation of diverse sources of load as well as generation while also increasing the reliability and resilience of the overall transmission system, especially during times of extreme weather and system stress. Regional transmission organizations and independent system operators (RTOs/ISOs), which coordinate organized wholesale markets and plan the bulk power system consistently account for reliability benefits from transmission projects but may not always completely account for the economic benefits to consumers. Likewise with utility planners in non-RTO/ISO regions. Investment in transmission also provides broader benefits, such as new jobs and economic development or support for the national security of the Unites States, which are not usually quantified. We will take each of these categories of benefits in turn.

## AFFORDABILITY AND RELIABILITY BENEFITS OF TRANSMISSION TO CONSUMERS

RTOs/ISOs have produced numerous regionwide studies and reports documenting the direct economic and reliability value transmission investment provides to consumers. The benefits typically quantified for these analyses include lower electricity costs through lower fuel and capacity costs for consumers and improved power system reliability and resilience.

### *Lower costs for consumers*

Across the country, transmission investments have delivered significant and measurable benefits to consumers by allowing access to lower cost generating resources and the associated reduction in production and congestion costs. For example, in the early 2000s, ISO-New England (ISO-NE) invested nearly $4 billion to expand its transmission system. As a result, congestion costs and reliability "uplift" payments dropped from around $700 million annually in 2005 and 2006 to under $100 million annually over the past decade. These costs now make up less than 2 percent of wholesale energy costs in the region.[6] Similarly, a 2019 PJM Interconnection (PJM) report found that coordinated transmission planning and operations provided $4 billion in expected annual benefits, including a $3.78 billion reduction in capacity costs and nearly $300 million in annual congestion cost savings.[7]

Other regions have seen similar returns. After reevaluating lines initially planned in 2012 and 2014, Southwest Power Pool (SPP) found that the expected benefits of these transmission

6 ISO-NE, *On the Horizon: 2022 Regional Electricity Outlook,* at 28 (June 2022), https://www.iso-ne.com/static-assets/documents/2022/06/2022_reo.pdf; *See also* ISO-NE, "Transmission," accessed July 3, 2025, https://www.iso-ne.com/about/key-stats/transmission.

7 *See* PJM, "PJM Value Proposition, (2019), https://www.pjm.com/-/media/DotCom/about-pjm/pjm-value-proposition.pdf.

investments rose from an initial estimate of $12 billion to $16.6 billion.[8] In 2017, Midcontinent Independent System Operator (MISO) also evaluated the long-term value of its Multi-Value Projects and projected between $12 billion and $53 billion in net benefits to consumers over 20 to 40 years. Compared to initial estimates from 2011, this represented a roughly 20 percent increase in net benefits, with an updated benefit-to-cost ratio of 2.2 to 3.4 to 1.[9] These results underscore the lasting value to consumers of proactive, long-term transmission planning.

Additionally, due to economies of scale, high-voltage transmission delivers power at the lowest per-unit cost and therefore underpins many of the benefits in this report. On a dollar-per-megawatt-mile basis, which reflects the average cost to develop infrastructure to deliver one megawatt of power one mile, economies of scale are substantial. A 765 kV line costs approximately 75% less than lower-voltage lines (230 kV) on a per-unit of power transfer capability basis. These technical efficiencies of scale make higher-voltage transmission more cost-effective for consumers than lower-voltage projects where multiple needs for transmission may arise.[10]

### *Improved power system reliability and resilience*

FERC and grid operators across the country have repeatedly emphasized that transmission is central to both grid reliability and resilience. In a 2020 report to Congress, FERC highlighted how high-voltage transmission allows utilities to share resources, recover more quickly after disruptions, and support grid stability and ancillary services.[11] Two years earlier, FERC launched a proceeding on bulk power system resilience that required RTOs and ISOs to explain how they assess and address resilience challenges. In their responses, every region underscored the need to prioritize transmission.[12] PJM, MISO, and California ISO (CAISO) all called for resilience to be explicitly incorporated into planning processes, stressing that transmission is not just a reliability tool but a necessary safeguard against a wide range of threats.[13] Beyond planning, operators such as New York ISO (NYISO), ISO-NE, and SPP showed how interregional connections and recent transmission upgrades have improved system performance during periods of stress, enabling greater resource diversity and operational flexibility.[14] Electric Reliability Council of Texas (ERCOT) and the Public Utility Commission of Texas added that transmission must be designed to continue delivering power even after unexpected losses of generation or

8 Sw. Power Pool, Inc. (SPP), *The Value of Transmission,* at 16 (Jan. 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

9 Midcontinent Indep. Sys. Operator (MISO), *MTEP17 MVP Triennial Review*, at 4-5 (Sept. 2017), https://cdn.misoenergy.org/MTEP17 MVP Triennial Review Report117065.pdf ("*MTEP17*").

10 MISO, *Transmission Cost Estimation Guide for MTEP24* (May 2024), https://web.archive.org/web/20240705181508/https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

11 FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, June 2020, https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

12 *See Grid Resilience in Regional Transmission Organizations and Independent System Operators,* Docket No. AD18-7-000, 162 FERC ¶ 61,012 (2018).

13 *See Comments and Responses of PJM Interconnection, L.L.C.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5192&optimized=false; *See also Responses of the Midcontinent Independent System Operator Inc.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5105; *See also Comments of the California Independent System Operator Corporation in response to the Commission's request for comments about system resiliency and threats to resilience*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5193&optimized=false.

14 *See Response of the New York Independent System Operator, Inc.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5183&optimized=false; *See also Response of ISO New England Inc.,* FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5121&optimized=false; *See also Comments of Southwest Power Pool, Inc. on grid resilience issues,* FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5161&optimized=false.

infrastructure.[15] Together, these perspectives reflect broad agreement that transmission is a critical foundation for a grid that can withstand and adapt to disruption.

These reliability and resilience benefits also provide economic savings to ratepayers, as they allow the same level of reliability to be met with less power plant capacity. This drives a significant share of the billions of dollars in regional benefits discussed in the preceding section.

## OTHER BENEFITS OF TRANSMISSION

Generally, RTO/ISO benefit-cost analyses for regional transmission portfolios do not evaluate, or evaluate separately, the broader societal benefits transmission investments provide. This section discusses additional benefits transmission investments provide that are not direct economic benefits for ratepayers including national security benefits as well as new jobs and economic development.

### *Support for the national security of the United States*

A robust and well-connected transmission network is essential to national security. The U.S. military relies on the electric grid for communications, intelligence operations, cybersecurity, logistics, and day-to-day readiness. During Winter Storm Uri, 12 of the 15 military installations in Texas experienced power disruptions and greater than 1,000 hours of unplanned outages were reported at Department of Defense installations.[16] A more resilient grid, reinforced by

15 *See Joint comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas,* FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5123&optimized=false.

16 Converge Strategies, *Transmission Expansion for National Defense,* at 13 (April 2024), https://convergestrategies.com/wp-content/uploads/2024/05/TransmissionExpansionForNationalDefenseTREND_April2024_CSL_ADC.pdf.

expanded transmission, ensures that military operations remain fully functional, including during emergencies, and that power can be quickly rerouted to critical installations when disruptions occur.

In addition, while backup generation is essential for mission readiness, it cannot replace the reliability of a resilient grid connection. According to NERC data, transmission lines, across voltages, typically achieve about 99.85% availability (with the broader transmission system performing at a considerably higher rate), far exceeding any single generation source.[17] As an example of a close call, during Winter Storm Uri, a U.S. Air Force base in Louisiana switched to backup generators that performed as designed, but the installation struggled to secure enough fuel to keep them running.[18]

### *New jobs and economic development*

Transmission projects are major infrastructure investments that often require hundreds of millions to billions of dollars in capital. Due to their scale, both the construction and ongoing operation of these projects generate a significant number of jobs. In addition, transmission infrastructure facilitates the development and interconnection of new generation resources, which themselves create substantial employment opportunities across similar categories. Furthermore, transmission development helps reduce electricity costs, which can drive broader economic growth by attracting new industries and supporting existing businesses through improved access to affordable and reliable power. A subsequent section reviews economic literature to assess the employment effects from delayed transmission development.

Significant investment in transmission infrastructure generates skilled-labor employment opportunities across construction, operations, and maintenance, while also reinforcing domestic manufacturing and supply chains. Building new transmission lines can stimulate U.S.-based production of essential equipment such as conductor cables, towers, transformers, and circuit breakers. As demand for these components grows, it can lead to expanded domestic manufacturing capacity and additional jobs in areas like engineering, logistics, and project management.[19]

Beyond these direct impacts, expanded transmission capacity is essential to advancing national strategies aimed at revitalizing American manufacturing and securing resilient supply chains. Access to reliable and affordable electricity is a key consideration for businesses, particularly in energy-intensive industries such as manufacturing and data centers. Elevated electricity costs can undermine competitiveness and prompt firms to move operations abroad. By facilitating access to reasonably priced and reliable power, transmission development supports industrial growth and strengthens the long-term economic position of the United States.

17 NERC Transmission Availability Data System. https://www.nerc.com/pa/RAPA/tads/pages/default.aspx (“*Transmission Expansion for National Defense»)*.

18 *Transmission Expansion for National Defense* at 13.

19 *See generally,* J. Pfeifenberger & D. Hou, The Brattle Group & WIRES, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada* (May 2011), https://www.brattle.com/wp-content/uploads/2017/10/8209_employment_and_economic_benefits_of_transmission_infrastructure_investmt_pfeifenberger_hou_may_2011_wires.pdf (“*Employment and Economic Benefits of Transmission*”).

# IMPACTS OF DELAYS IN TRANSMISSION PLANNING AND DEVELOPMENT

Transmission is generally a small portion of consumers' bills,[20] but delaying development prevents consumers from reaping the benefits, thereby increasing costs and postponing the realization of broader benefits. When transmission development is postponed, consumers and the country face both direct and indirect costs.

We find the following costs of delays: (1) reduced production cost savings (i.e., the ability to operate the power system more efficiently); (2) delays in connecting lower cost generation; (3) potential increased need for less comprehensive solutions; (4) increased direct costs from other factors such as siting and permitting delays; (5) increased materials-related costs; and (6) indirect societal costs from reduced economic growth, including job creation.

This section discusses the results of the analysis along with the economic and reliability impacts of delay in greater detail and assesses how those costs accumulate beyond foregone benefits.

## RESULTS: DELAYING TRANSMISSION PLANNING AND DEVELOPMENT HAS SIGNIFICANT RELIABILITY AND ECONOMIC IMPACTS ON CONSUMERS

For this report's methodology, we evaluated eight benefit-cost analyses for transmission portfolios across the country, including transmission portfolios from NYISO, MISO, SPP, and ERCOT. The analysis was constituted of the following steps to arrive at comparable and generalizable results:

- First, we extracted total reliability and economic benefits identified in each study and converted them to annualized benefits using the study's stated discount rate and analysis period.
- Second, we also calculated annualized costs using the same discount rate and each study's cost assumptions.
- Third, we calculated annual net benefits as annualized benefits minus annualized costs.
- Finally, we estimated the consumer cost of a one-year delay by treating it as one-year of foregone annualized net benefits that accrues when the in-service date of each regional transmission portfolio is delayed one year.

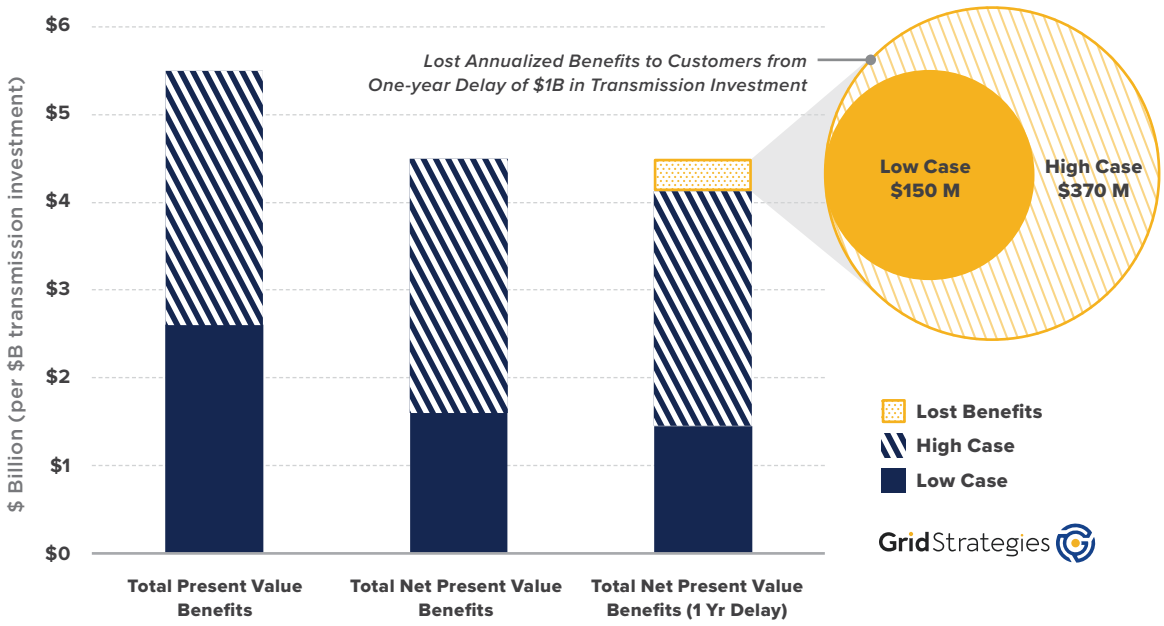
For a more detailed discussion of the methodology and regional portfolios, please see the appendices.

20 EIA, *Annual Energy Outlook 2025: Table 8. Electricity Supply, Disposition, Prices, and Emissions* (Apr. 2025), https://www.eia.gov/outlooks/aeo/tables_ref.php.

### *Estimated cost of delay to customers per unit of infrastructure investment*

Using the methodology described above, we find that for every $1 billion in delayed, proactive, large-scale transmission investments, consumers lose out on benefits of $150-$370 million every year, even after accounting for the cost of transmission.

**FIGURE 1** | Benefits lost from delaying transmission one year (per $Billion invested)




Considering the time value of money, the near-term benefits that consumers lose due to delayed large-scale transmission projects are those with the highest value to consumers. The time value of money reflects that consumers could invest money saved on their electric bills today, yielding greater value in future years. Because of this concept, the benefits to consumers from transmission development — and particularly large-scale, coordinated planned transmission — are greater the sooner the projects are actually energized and can begin delivering those benefits to consumers.

Much of the estimated cost in delay for each transmission plan and portfolio stems from forgone production cost savings, which may be especially pronounced in regions with abundant low-cost resources. In particular, MISO, SPP, and ERCOT have some of the lowest generation costs in the country. As a result, the projected production cost savings from transmission expansion in these areas may be higher than in regions with higher generation costs. However, because these regions already have relatively lower generation costs, the incremental benefits of new transmission on generation costs may be less significant than in regions where there are more opportunities for transmission to allow low-cost resources to displace higher-cost energy sources.

As discussed above, our analysis was based on a review of eight different transmission portfolios from across the country. These portfolios represent billions in investments and

thousands of miles of large-scale transmission. Climate benefits that were quantified were removed where possible, and we provide detailed discussion of the portfolios, benefit-cost analyses, and consumer costs for each region in Appendix II. The table below provides a summary of each regional transmission portfolio and the associated cost to the region from delaying the energization of the portfolio one year.

**TABLE 1** | Summary of regional transmission portfolios evaluated and estimated cost of delay

| Region | Portfolio | Total Benefits | Upfront Cost | Benefit-Cost Ratio | Estimated consumer cost from 1-year delay |
|---|---|---|---|---|---|
| MISO | MVP | $12 billion | $6.5 billion | 1.8 | $1.4 billion |
| MISO | LRTP Tranche 1 | $27 billion | $10.3 billion | 2.6 | $1.8 billion |
| MISO | LRTP Tranche 2.1 | $44 billion | $21.9 billion | 1.8 | $1.5 billion |
| ERCOT | CREZ | $84 billion | $6.9 billion | 12.2 | $6.3 billion |
| SPP | RCAR III | $42 billion | $7.3 billion | 5.76 | $2.9 billion |
| SPP | 2023 ITP | $2.6 billion | $1.1 billion | 2.29 | $0.123 billion |
| SPP | 2024 ITP | $88.7 billion | $7.7 billion | 8.23 | $7.7 billion |
| NYISO | AC PPTN | $1.7 billion | $1.1 billion | 1.5 | $0.132 billion |

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### *Estimated cost of national delay*

To further illustrate the national value of transmission beyond the regional portfolios for which benefit analyses were available, we extrapolated the regional portfolio results described above to estimate the national consumer cost of a one-year delay. This hypothetical assumes every region of the country planned a transmission portfolio similar to those studied, and that those portfolios were all similarly timed for development and then delayed by a year. We estimate that delaying by one year such a set of national transmission investments, sized to the average of the regional portfolios we evaluated, would cost Americans between $15 billion and $41 billion. To arrive at this estimate, we annualized each regional portfolio's total net benefits, divided by load to derive dollars per megawatt-hour (MWh), and weighted by portfolio size. This analysis is based on the broader finding that large scale transmission development delays cost consumers an average of $3.89–$9.88 per MWh of electricity consumed in regions where transmission portfolios are planned and may be delayed.

While the national extrapolation described above is an unrealistic scenario, other research using different methods of analysis produces similar results. A report titled *Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays* released in May 2025 finds that delaying a set of nationwide transmission investments would increase the cost of

electricity and natural gas together by $22 billion.[21] While our analysis relies on extrapolation from existing regional benefit-cost analyses, the *Power Delayed* report relies on a top-down modeling approach that uses a power sector model that represents the US and Canadian grids to look at the impact on electricity prices if national transmission capacity expansion is delayed.[22] Despite the differences in methodology, both reports show similar costs to US consumers from delays in transmission development.

### *Discussion of transmission benefits lost to delays*

The portfolios we reviewed show that transmission delivers substantial benefits. A significant portion of the benefits comes from reduced production costs, which include lowering congestion, fuel savings, and reduced variable operating expenses. Benefits also accrue by avoiding or deferring generation investments by enabling regions to share power across geography and time. For both categories of benefits, when transmission is delayed the benefits are not recoverable. Operational savings do not accrue retroactively, and delayed transmission can lock in higher-cost generation to meet reliability and resource adequacy. Delays in transmission development therefore permanently diminish consumer value.

As an example, today, where grid operators are facing significant load growth, delaying transmission may require additional generation development to meet increased demand. This is, in part, due to the timing mismatch between the addition of load, development of generation, and transmission. It may take only one or two years to connect new load to the grid, but analysis from Lawrence Berkeley National Laboratory shows it may take almost 5 years from interconnection request to commercial operation to connect new generation, and new transmission may take even longer (MISO's Tranche's 1 and 2.1 estimated in-service dates are between 6 and 10 years).[23] The time it takes to develop large-scale transmission is one key reason why proactive transmission planning is critical.

## RELATED PROJECT COSTS INCREASE WHEN TRANSMISSION IS DELAYED

In addition to reducing benefits for consumers, delays in transmission construction also result in direct increases to project costs. These cost increases can stem not only from increased material or labor expenses, but can also arise from other related factors, such as engineering and procurement costs or legal fees associated with litigation.

Once a transmission project is planned, there are numerous categories of project costs that begin to add up if the project experiences delays. Some of these costs can include legal and public relations fees, administrative and project management overhead, engineering and procurement costs, as well as permitting and regulatory fees (e.g., environmental studies).

21 D. Shawhan, *et al.*, Resources for the Future, *Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays*, at v (May 2025), https://media.rff.org/documents/WP_25-14.pdf .

22 *Id.* at 5-10.

23 Rand, Joseph, *et al. Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023*, Lawrence Berkeley National Laboratory at 41 (2024). https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf; MISO, *LRTP Tranche 1 Appendix A*, (2022), https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx; MISO, "LRTP Tranche 2.1 Portfolio Update," at 2 (2024), https://cdn.misoenergy.org/20240924%20LRTP%20Workshop%20Item%2002%20Tranche%202.1%20Final%20Portfolio%20Overview649676.pdf.

Based on estimates from developers, project engineering and procurement costs, excluding the cost of capital, contribute significantly to project cost escalation when there are delays. Interviews with utility and independent transmission developers suggest that each year of delay increases project costs by at least 20%.[24] As an example, it takes an average of 4.5 years for relevant authorities to complete an environmental impact statement (EIS) under the National Environmental Policy Act (NEPA), but it takes longer than six years for roughly one quarter of transmission projects. That 1.5-year delay alone can increase project costs by almost one-third.[25]

Currently, there is a lack of comprehensive data regarding cost escalation for transmission projects that have experienced delays. One example where some data does exist is the New England Clean Energy Connect (NECEC). The NECEC is a 145-mile, 320 kV HVDC transmission line that involves both greenfield transmission development and upgrades to existing transmission lines to move 1,200 MW of power from Canada into New England. The construction of the transmission line was delayed for roughly two years from 2021 to 2023 due to a ballot initiative in Maine and legal challenges. The line is now slated to come online in late 2025 or 2026. The original cost estimate from 2019 was just under $1 billion. The two-year delay in construction led to $521 million in overall project cost increases, an almost 50% escalation, bringing total project costs to just over $1.5 billion.[26]

Taking another example, in the Midwest, the Cardinal-Hickory Creek line has faced similar delays while under construction. Cardinal-Hickory Creek is a 100-mile, 345 kV AC transmission line, planned as part of MISO's 2011 MVPs. The original plan had the transmission line in-service in 2020, with an estimated cost of $798 million. Litigation caused delays, such that the line did not enter into service until the end of 2024.[27] The final project cost, according to MISO, was $1.034 billion. This means that delays added a little over $200 million to the original cost, or roughly a 25% increase. These kinds of cost escalations represent a cost to consumers but are not captured by our analysis in this report.

### *Delays in transmission development can defer job creation and may result in permanent losses in economic growth*

Delaying the development of transmission also has near-term economic impacts in the communities and sectors that rely on electric service. Since the assumption is the lines will eventually get built, the effects of the delay are less permanent, but can have cascading effects for the economic health or growth of a state or region.

In terms of job creation, both alternating and direct current transmission lines yield substantial, though slightly different, employment opportunities. Based on a review of several different

24 J. Connaughton, Wall Street Journal Opinion, "A Simple Way to Cut NEPA's Red Tape," (Dec. 2024), https://www.wsj.com/opinion/a-simple-way-to-cut-nepas-red-tape-environmental-laws-supreme-court-38e7f6fd?st=LoHZG3&reflink=article_copyURL_share; Information in opinion article supplemented in subsequent emails with author.

25 *See* Council on Environmental Quality, "Environmental Impact Statement Timelines (2010-2018)," (Jun. 202), https://ceq.doe.gov/docs/nepa-practice/CEQ_EIS_Timeline_Report_2020-6-12.pdf.

26 *See* J. Knapschaefer, ENREast, "Embattled Maine Power Line Restarts as Cost Balloons to $1.5B," (Aug. 2023), https://www.enr.com/articles/56895-embattled-maine-power-line-restarts-as-cost-balloons-to-15b; *See also* B. Mohl, Commonwealth Beacon, "Mass. ratepayers to pay $521m more for hydroelectricity because of Maine political delays," (Oct. 2024), https://commonwealthbeacon.org/energy/mass-ratepayers-to-pay-521m-more-for-hydro-electricity-because-of-maine-political-delays/#:~:text=Under%20terms%20of%20the%20power,to%20just%20over%20$1.5%20billion.

27 A. Durish Cook, "Conservation Groups File Another Lawsuit to Stop Cardinal-Hickory Creek's Last Mile," RTO Insider, (Mar. 2024), https://www.rtoinsider.com/73353-conservation-groups-lawsuit-stop-cardinal-hickory-creek-last-mile/#:~:text=(See%20Wisconsin%20Tx%20Project%20Clears,the%20route%20through%20the%20refuge.

economic impact studies, investment in direct current transmission projects creates around 4,000 direct job-years for every $1 billion invested, and 7,300 indirect and induced job-years. For alternating current transmission projects, per $1 billion invested, there are around 11,500 new direct job-years and 15,500 indirect and induced job-years. The table below summarizes the results from five different economic input-output models estimating the direct, indirect, and induced job-years created by transmission construction.

**TABLE 2** | Summary of studies of job creation from transmission investment

| **Type of line** *(AC or DC)* | **Construction Direct Job-Years** *(per $1 billion invested)* | **Construction Direct, Indirect, and Induced Job-Years** *(per $1 billion invested)* |
|---|---|---|
| AC[28] | 9,000 to 14,000 | 19,000 to 35,000 |
| AC + DC[29] | 11,720 | N/A |
| AC + DC[30] | 4,250 | 12,500 |
| DC[31] | 3,000 to 4,000 | N/A |
| DC[32] | 5,050 | 11,300 |

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28 *See* MISO, *Economic Impact of MTEP In-Service Projects from 2005-2015*, (Jul. 2015).

29 *See* D. Swenson, *Economic Impact & Job Creation Relative to Large-Scale, High Voltage Transmission Infrastructure*, (Jul. 2018), http://www2.econ.iastate.edu/prosci/swenson/Publications/The%20Interconnection%20Seam%20Study%20Amended%20Title.pdf.

30 *See Employment and Economic Benefits of Transmission.*

31 *See* J. Duan & J. Frayer, *Estimating Macroeconomic Benefits of Transmission Investment with the REMI PI+ Model* (May 2018), http://www.remi.com/wp-content/uploads/2018/05/WIRES-modeling_0501_final-v3.pdf.

32 *See* E. Lantz & S. Tegen, *Jobs and Economic Development from Net Transmission and Generation in Wyoming* (Mar. 2011), https://www.nrel.gov/docs/fy11osti/50577.pdf.

Looking at $55 billion of planned transmission investments in the MISO and SPP regions that have not yet been constructed, using the estimates in the table above, delaying those projects would defer the development of 638,000 direct job-years and nearly 150,000 indirect and induced job-years. The table below provides a summary of the jobs impacted by delays to the individual transmission portfolios in MISO and SPP.

**TABLE 3** | Direct, indirect, and induced job-years impacted by delaying planned transmission projects (MISO LRTP Tranche 1 & 2.1 and SPP 2023 & 2024 ITP)

| Large-scale Regional Expansions | Total Cost | Direct Jobs-Years | Indirect Jobs-Years |
|---|---|---|---|
| MISO LRTP Tranche 1 | $14.1 billion | 162,225 | 218,651 |
| MISO LRTP Tranche 2.1 | $28.6 billion | 328,900 | 443,300 |
| SPP 2024 ITP | $11.6 billion | 133,538 | 179,986 |
| SPP 2023 ITP | $1.1 billion | 13,110 | 17,670 |
| Total | $55.4 billion | 637,773 | 859,607 |

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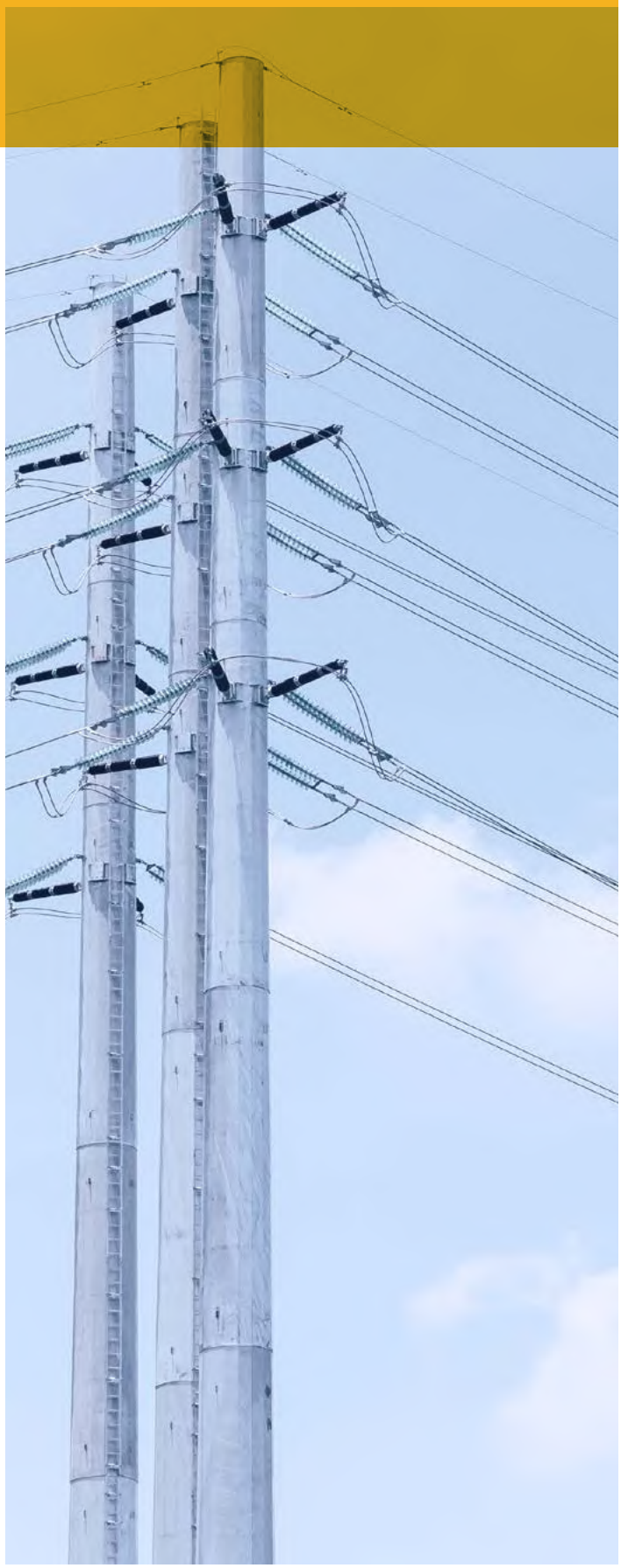
The direct and indirect job-year creation estimates do not account for any of the jobs related to new generation investments that are enabled by new transmission capacity. As an example, as previously discussed, approximately 17 GW of new generation across 160 projects depended on the construction of the Cardinal-Hickory Creek transmission line.[33] Not only did the construction delays prevent new generation from coming online, but based on economic literature, they also impacted an additional 180,000 direct and indirect jobs.[34]

Additionally, the PA Consulting Group found that delaying the CREZ projects for five years would have reduced the total economic output of Texas from 2010-2017 by $8 billion and would have cost Texans, on average, 5,800 new direct, indirect, and induced jobs. Their estimate was from both induced economic output from new jobs and due to retail consumer energy cost savings and increased construction and economic operations activities.[35] These benefits would have been delayed nearly half a decade, or never realized, if the CREZ projects had not been planned and constructed.

33 American Transmission Co, ITC Holdings Corp., Dairyland Power Cooperative, "Cardinal-Hickory Creek Transmission Line Project," accessed July 3, 2025, https://www.cardinal-hickorycreek.com/.

34 Luigi Aldieri, Jonas Grafström, Kristoffer Sundström, and Concetto Paolo Vinci, "Wind Power and Job Creation," Sustainability, (December 18, 2019), at 16, available at: https://www.mdpi.com/2071-1050/12/1/45/pdf, showing 4.03 direct and 10.64 direct and indirect jobs per MW of wind capacity; and The Solar Foundation, National Solar Jobs Census 2018, at 30, available at: https://resources.solarbusinesshub.com/images/ reports/206.pdf, showing 3.3 installation and development jobs/MW for utility-scale solar, rounded up to 4 jobs/MW to account for manufacturing and other supply chain jobs.

35 PA Consulting Group at 24-27.



# CONCLUSION

Delays in large-scale regional transmission development impose substantial and lasting economic loss on consumers; while diminishing the economic and reliability benefits that regional transmission projects and portfolios can achieve. Evaluation of benefit-cost analyses from regions across the country, including ISO-NE, NYISO, MISO, SPP, and ERCOT, demonstrate that a single year of delay to planned transmission projects costs consumers delayed net benefits of $150 million to $370 million for every $1 billion in transmission investment. The benefits foregone are particularly valuable in the near term, when timely investment could deliver the greatest savings and economic impact on a real dollar basis for customers. Delays can also increase project costs through increased project expenses while also delaying job creation and slowing economic development by reducing access to reliable, low-cost electricity for new businesses. These costs to consumers highlight the importance of timely development of regional transmission to ensure consumers realize the full scope of benefits associated with large-scale infrastructure expansion.

# APPENDIX I
# METHODOLOGY

This Appendix describes the methodology that was used to process the results from the various RTO/ISO benefit-cost analyses and how those results were then used to calculate the cost to customers of delays in transmission development.

1. **Collect study results**: We began by collecting studies of the benefits and costs of eight regional transmission portfolios.[36]
    a. Some studies report a low and high range for some transmission benefits. Where available, these were used to develop the low and high cost estimates in our analysis.

2. **Annualize cost and benefit expectations:** Starting from total customer benefits and customer costs from ISO/RTO studies, we annualized benefits and costs using the same discount rates and study periods used in each benefit-cost study.
    a. It is important to note that year-over-year benefit streams and revenue requirements are not the same as the annualized results, but generally they are close and, importantly, making use of annualized results allows us to compare across studies.
    b. This approach was further necessitated by the fact that some regions have detailed year-by-year benefits and revenue requirements across the study period, other benefit-cost analyses evaluated in this report do not include detailed year over year trajectories, so we were not able to report those details or compare on the basis of annual cost and benefit trajectories with a high degree of granularity.

3. **Calculate net benefits:** Once we had annualized benefits and costs, we calculated annual net benefits by taking the difference between the two.

4. **Calculate lost net benefit per unit of investment:** To estimate costs to consumers of lost net benefits resulting from a one-year delay per unit of investment, we summed the annualized net benefits for each portfolio for a single year and divided by the total upfront investment for all of the portfolios.
    a. For our analysis, it was assumed that the foregone annualized net benefits when the in-service date of each regional transmission portfolio is delayed is the equivalent of cost to consumers.

5. **Calculate total load expectations for regions with benefit studies, as well as total nationwide load expectations:** For the national extrapolation, we used total electricity consumption (in MWh) during the study period, either as reported in the benefit-cost

36 The benefit-cost analyses used for the analysis are cited above in the results and discussion section of the report.

analysis or obtained from the region's annual load forecast or FERC Form 714. We then multiplied this total consumption by the lost net benefits per unit for the regions covered in the RTO/ISO benefit studies.

   a. If the load forecast did not cover the full study period, we extrapolated the remaining years using the region's annual growth rate in the load forecast.

6. **Calculate net benefits lost per unit of energy consumed**: Calculate costs to consumers in dollars per MWh by dividing the total net benefits lost by total electricity consumption for the relevant region.

7. **Calculate net benefits lost for hypothetical nationwide case:** To estimate total cost to U.S. consumers, we used the national total annual energy from FERC Form 714 data. We then multiplied the cost to consumers in dollars per MWh (above) by FERC's Form 714 total annual energy.

37 FERC, "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report," accessed September 2024, https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.

# APPENDIX II
# REGIONAL RESULTS

This Appendix provides an in-depth discussion of the eight regional transmission portfolios from MISO, ERCOT, SPP, and NYISO reviewed in this report. The Appendix includes discussion of the portfolio's benefit-cost analyses, identifies the main drivers of benefits, and summarizes the costs to consumers if the portfolios are delayed.

## MISO

For MISO, we looked at three major portfolios MISO developed over the last 15 years: the Multi-Value Projects (MVP); the Long Range Transmission Planning (LRTP) Tranche 1; and the LRTP Tranche 2.1. MISO approved the initial MVPs in 2011, which consisted of 11 projects totaling just over $6.5 billion.[38] When MISO reevaluated the initial projects in 2017, MISO found that the benefits had increased from the initial 2011 analysis to provide between $12 and $53 billion of estimated new benefits over the next 20 to 40 years, increasing the benefit-to-cost ratio from the originally estimated 1.8 to 3.0, to the new estimate of 2.2 to 3.4.[39]

For the MVPs, the benefit-cost analysis showed that most of the savings to consumers come from production cost savings, specifically fuel and congestion savings. Over 90% of the savings to consumers from the MVPs—$20.1 billion out of $22.1 billion—are fuel and congestion savings that are achieved through more efficient grid operations. The remaining 10% of benefits come from lower power losses across the system ($234 million), avoided transmission investments ($299 million), and more efficient siting of new generation ($1.3 billion).[40] Based on the 2017 analysis, we find that if construction of the entire portfolio had been delayed one year it would have cost MISO North and Central[41] consumers around $1.4 billion, or $2.84 per MWh in forgone net benefits.

Our findings are similar for MISO's LRTP Tranches 1 and 2.1 portfolios. MISO's LRTP Tranche 1 consists of 18 transmission projects estimated to cost just over $10.3 billion, with benefit-to-cost ratios ranging from 2.6 to 3.8, depending on the scenario.[42] Similar to the MVPs, one of the largest benefits to consumers of the Tranche 1 projects comes from congestion and fuel savings. MISO estimates that the more efficient operation of the grid will provide $13.1 billion in benefits, or 35% of the total benefits to consumers. However, the largest benefit of the LRTP Tranche 1 portfolio is avoiding higher costs from otherwise building less efficient generation. MISO estimates the avoided additional capital investments to be $17.5 billion, or 47% of the total

38 MISO, *Regionally Cost Allocated Project Reporting Analysis: 2011 MVP Portfolio Analysis Report* (Apr. 2025), https://cdn.misoenergy.org/MVP%20Dashboard117055.pdf?v=20240131144844.

39 *MTEP17* at 4-6.

40 MTEP17 at 23.

41 MISO operates the electric transmission system in portions of 15 states in the Midwest and the South, plus the Canadian province of Manitoba. MISO North and Central includes all states not in the MISO South region, which includes parts of Arkansas, Mississippi, Louisiana, Texas. MISO added the South region in 2013 after the approval of the MVP portfolio. FERC, *Participation in Midcontinent Independent System Operator (MISO) Processes* (Apr. 2024), https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes.

42 MISO, *MTEP 2021 Report Addendum: Long Range Transmission Planning Tranche 1* (May 2025), https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf ("MTEP 2021").

consumer benefits. The remaining 18% of benefits came from avoided transmission investments ($1.3 billion), resource adequacy savings ($600 million), avoided power outages ($1.2 billion), and reduced emissions ($3.5 billion), the last of which we did not include in our analysis.[43] We find that delaying the construction of the LRTP Tranche 1 portfolio one year would cost MISO North and Central consumers approximately $1.8 billion per year, or $3.62 per MWh in forgone net benefits. If we include emissions benefits the societal cost to consumers rises to $2.2 billion per year, or $4.26 per MWh in forgone net benefits.

The second phase of MISO's LRTP process led to the approval of a 24-project, $21.8-billion portfolio (i.e., MISO LRTP Tranche 2.1). MISO estimates the lines will be in service between 2032 and 2034 and, once energized, will provide between $1.80 to $3.50 in benefits to MISO consumers for every $1 invested.[44] For the LRTP Tranche 2.1 transmission projects, MISO evaluated additional reliability benefits, resulting in the second largest benefit to consumers, making up 29% of the total, of $14.8 billion in savings from power outage reductions. The single largest benefit MISO estimated was avoided generation investments of $16.3 billion, or 32% of the total consumer benefits. Congestion and fuel savings were the third largest benefit at 16% of the total benefits of $8.1 billion. The remaining benefits represent 22% of the total benefits and include savings from more efficient transmission lines ($3.5 billion), reduced impacts from extreme weather ($400 million), avoided investments in transmission lines ($1.2 billion), and reduced emissions ($7.2 billion), the last of which we did not include in our analysis.[45] We find that delaying the construction of this portfolio by one year would cost MISO North and Central consumers another $1.5 billion, or $2.83 per MWh in forgone net benefits to consumers.[46] If we include emissions benefits the societal cost to consumers rises $2.2 billion, or $4.13 per MWh in forgone net benefits to consumers.

## ERCOT

For ERCOT, we review analysis of the Competitive Renewable Energy Zone (CREZ) portfolio, which ERCOT started planning in 2005. The CREZ portfolio includes more than 3,500 miles of 345 kV transmission lines, which enabled the interconnection of 18.5 GW of new generation and cost $6.9 billion.[47] In 2018, the PA Consulting Group estimated that the CREZ projects had already provided almost $6 billion in benefits and would provide an additional $78 billion through 2037.[48] Using the results from this analysis, we find that delaying construction of the CREZ projects for one year would have cost ERCOT consumers around $6.3 billion, or $13.34 per MWh in forgone net benefits to consumers. These costs to consumers come from delaying two benefits: production cost savings from more efficient power grid operation and the addition of lower-cost energy. Production cost savings represent about 44% of the total benefits, or $36.7 billion, while lower energy costs are the remaining 56%, or $47.5 billion.[49]

43 MTEP 2021 at 3.

44 *Id.*

45 MTEP 2024 at 159-162.

46 MISO, *MTEP 2024 Transmission Portfolio*, at 159-162 (Dec. 2024) https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf ("MTEP 2024").

47 Powering Texas, *Transmission & CREZ Fact Sheet*, https://www.poweruptexas.org/wp-content/uploads/2020/11/Transmission-and-CREZ-Fact-Sheet.pdf (last accessed May 27, 2025).

48 PA Consulting Group, *The Long-Term Impact of Marginal Losses on Texas Electrical Retail Customers,* at 6 (Apr. 2018), https://interchange.puc.texas.gov/Documents/47199_93_977285.PDF ("PA Consulting Group").

49 *Id.*

## SPP

For SPP, we looked at three major benefit-cost analyses: Regional Cost Allocation Review (RCAR) III; the 2023 Integrated Transmission Plan (ITP); and the 2024 ITP. In the RCAR III, SPP reviewed all projects under its Highway/Byway Cost Allocation Methodology[50] that were approved for construction after 2010 and placed in service prior to 2020. SPP found these lines to be highly beneficial to SPP consumers, estimating total benefits over 40 years to be around $42 billion with an overall benefit-to-cost ratio of 5.76 to 1.[51] Based on these findings, we estimate that delaying construction of the projects that SPP evaluated in its RCAR III for one year would have cost consumers in SPP around $2.9 billion, or $7.70 per MWh in forgone net benefits. In the RCAR III study, 88% of the benefits come from what SPP calls "Operational Results," which include the benefits from a more efficient grid, such as fuel cost and congestion savings.[52]

For SPP's more recent ITPs, we see similar results. We estimate that delaying construction of SPP's 2023 and 2024 ITP projects for one year would have cost consumers $123 million and $7.7 billion, or $0.28 or $16.37 per MWh in forgone net benefits to consumers, respectively.

The 2023 ITP portfolio was smaller portfolio than in 2024, with only 51 new miles of 345 kV transmission, costing $1.1 billion. Even so, SPP estimates the 2023 ITP projects will still reduce production costs by $2.61 to $2.98 billion over 40 years, resulting in a benefit-to-cost ratio of 2.29-2.61.[53] According to SPP, "[t]he recommended consolidated portfolio is expected to be cost beneficial within the first year of being placed in-service and to pay back the total investment within the first 10 years."[54] These are tangible savings that will lead to increases in residential electric bills if the 2023 ITP portfolio is delayed.

The 2024 ITP is a larger plan that adds nearly 1,500 miles of 345 kV lines and almost 300 miles of 765 kV lines, and costs $7.68 billion. Though higher cost, the plan likewise yields higher benefits. SPP estimates the 2024 ITP projects will lower production costs by $88.7 to $95.7 billion over 40 years, resulting in a benefit-to-cost ratio of 8.23 to 8.88.[55]

As with the RCAR evaluation, the main benefit in SPP's 2023 and 2024 ITPs was production cost savings. In the 2023 and 2024 ITPs, production cost savings accounted for 85% of the total benefits to SPP consumers.[56]

50 SPP has a hybrid cost allocation methodology where it allocates the costs of high-voltage transmission facilities (300 kV+) regionally on a postage-stamp basis. For lower-voltage transmission facilities (100 kV-300kV), 33% of the costs are still allocated regionally on a postage-stamp basis, while 67% of the costs are allocated to the SPP pricing zone in which the facilities are located. Under 100 kV, costs are allocated entirely to the SPP pricing zone in which the facilities are located. *See Sw. Power Pool, Inc.*, 187 FERC ¶ 61,123 (2024), https://spp.org/documents/71722/20240531_order%20-%20byway%20facilities%20allocated%20on%20a%20region-wise%20basis_er24-1583-000.pdf.

51 SPP, *Regional Cost Allocation Review (RCAR III) Final Report*, at 42 (Jan. 2023) https://www.spp.org/documents/71083/rcar%20iii%20report%20final%2020230130.pdf.

52 *Id.*

53 SPP, *2023 Integrated Transmission Planning Assessment Report*, at 1 (Nov. 2023), https://spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf ("SPP 2023 ITP").

54 *Id.* at 4.

55 SPP, *2024 Integrated Transmission Planning Assessment Report*, at 1 (Jan. 2025), https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf ("SPP 2024 ITP").

56 SPP 2023 ITP at 160; SPP 2024 ITP at 185.

## NYISO

For NYISO, we reviewed the benefit-cost analysis for NYISO's AC Public Policy Transmission Needs Segments A and B, which NYISO approved in 2017. NYISO estimated the two projects would cost New York consumers an estimated $1.1 billion and provide between $1.7 and $2.8 billion in benefits.[57] Based on these findings, we estimate that delaying construction of Segments A and B for one year would have cost consumers in New York around $132 million, or $0.81 per MWh in forgone net benefits to consumers. These costs of delay are smaller than for some of the regional portfolios we reviewed. However, this is not surprising given that the plan includes only two projects (Segments A and B). The benefits to New York consumers are relatively evenly split between production cost savings (45%), avoided generation investments (22%), and avoided transmission investments (33%).[58]

57 NYISO, *AC Transmission Public Policy Transmission Plan*, at 39, 69, 130 (Apr. 2019), https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/23cbba74-a65e-66c2-708e-eaa0afc9f789.

58 *Id.* at 39, 69, 130.

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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.